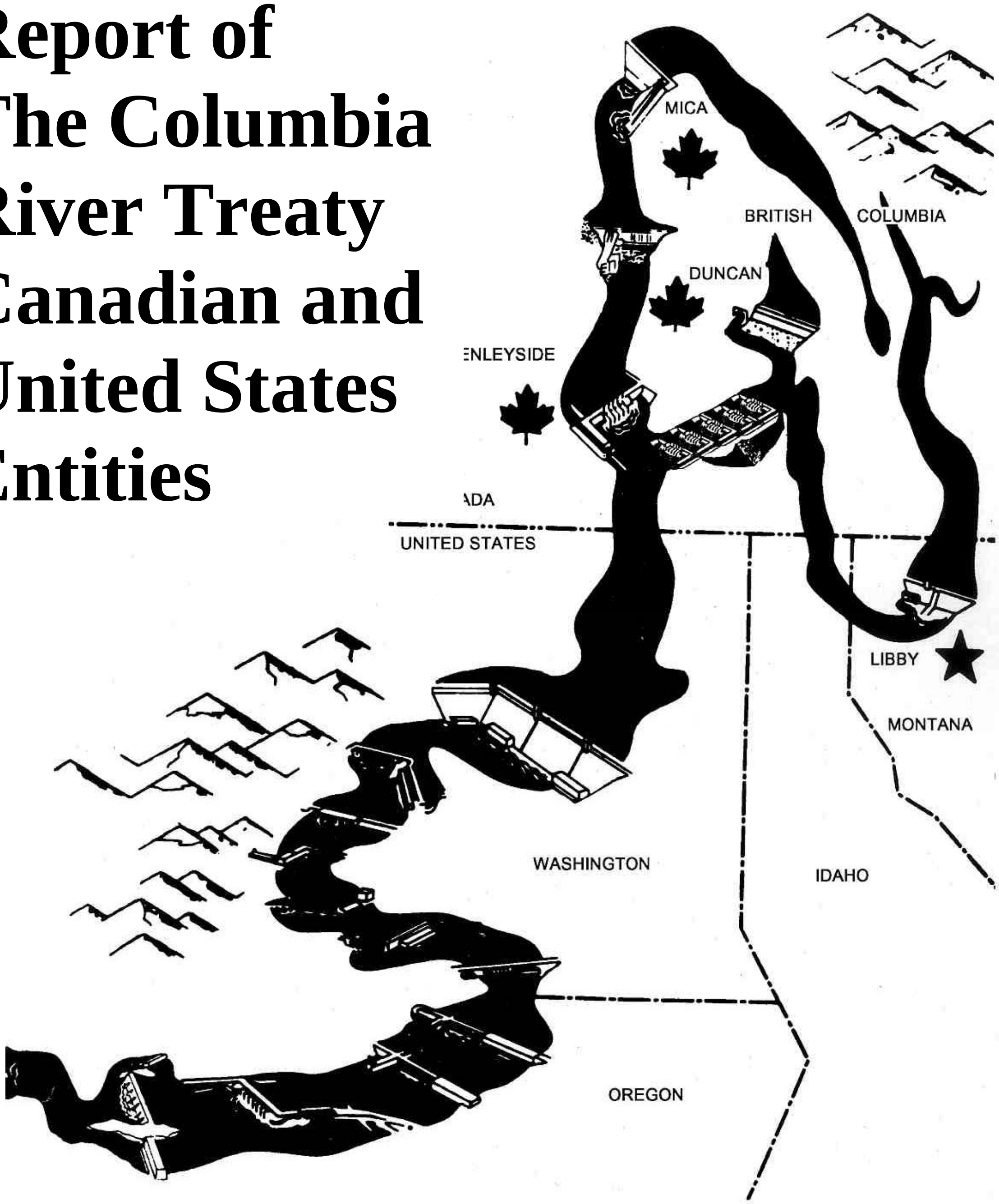
Annual Report of The Columbia River Treaty Canadian and United States Entities



For the Period
1 October 2005 through
30 September 2006

ANNUAL REPORT OF
THE COLUMBIA RIVER TREATY
CANADIAN AND UNITED STATES ENTITIES

FOR THE PERIOD
1 OCTOBER 2005 – 30 SEPTEMBER 2006

Published December 2006
(With minor edit corrections in January 2007)

EXECUTIVE SUMMARY

General

The Canadian Treaty projects, Mica, Duncan, and Arrow were operated during the 1 August 2005 – 30 September 2006 reporting period according to the 2005-2006 and 2006-2007 Detailed Operating Plans (DOPs), 2003 Flood Control Operating Plan (FCOP), and several supplemental operating agreements described below. The Libby project was operated according to the 2003 FCOP, Libby Coordination Agreement (LCA) dated February 2000, U.S. requirements for power and guidelines set forth in the U.S. Fish and Wildlife Service (USFWS), and the U.S. National Marine Fisheries Service (NMFS) 2000 and 2004 Biological Opinions (BiOps). Canadian Entitlement power was delivered to Canada in accordance with the DOPs and Entitlement related agreements described below.

Entity Agreements

Agreements approved by the Entities during the period of this report include:

- Columbia River Treaty Entity Agreement on the Assured Operating Plan and Determination of Downstream Power Benefits for the 2010-11 Operating Year, dated 6 February 2006.
- Columbia River Treaty Entity Agreement on the Detailed Operating Plan for Columbia River Storage 1 August 2006 through 31 July 2007, signed 22 June 2006.
- Columbia River Treaty Entity Agreement determining no adverse Treaty impacts of BPA-B.C. Hydro storage in non-Treaty space for 25 May – 30 September 2006, dated 26 June 2006.

Operating Committee Agreements

The Operating Committee completed one agreement entitled:"Columbia River Treaty Operating Committee Agreement on the Operation of Treaty Storage for Nonpower Uses for the Period 1 December 2005 through 31 July 2006," signed 16 December 2005.

In addition to the Operating Committee agreements listed here, the Bonneville Power Administration (BPA) and British Columbia Hydro and Power Authority (B.C. Hydro) developed an agreement entitled "2006 Summer Storage Agreement (Non-Treaty) for the Period 25 May 2006 to 30 September 2006," signed 8 June 2006.

System Operation

Under the 2005-2006 and 2006-2007 DOPs, Canadian Treaty Storage was operated according to criteria from the 2005-2006 and 2006-2007 Assured Operating Plans (AOP), except for a maximum limitation to Arrow January outflows. The 2005-2006 AOP included a flood control allocation of 6.29 cubic kilometers (km^3) (5.1 million acre-feet (Maf)) in Arrow and 2.57 km^3 (2.08 Maf) in Mica. B.C. Hydro requested a reallocation of the flood control space to operate to 5.03/4.44 km^3 (4.08/3.6 Maf) Mica/Arrow allocation. A process to implement the flood control reallocation without significantly changing the net Canadian outflows from the AOP was agreed to by the Committee on 13 July 2005.

Canadian Treaty storage began the operating year slightly below the DOP levels (by 121 hm^3 or 98.0 Kaf) determined in the Treaty Storage Regulation (TSR) study and was operated to forecasted TSR levels during August through December 2005, except for a small provisional draft authorized by the Libby Coordination Agreement. Substantial inadvertent draft occurred in December 2005, with Canadian storage ending the month 822.5 hm^3 (665.7 Kaf) below the TSR. This was caused by a large change in December composite Treaty storage content of about 863 hm^3 (700 kaf) in the final TSR run in January. The January TSR incorporated large inflow changes that materialized after the last TSR was run in December. In accordance with a Supplemental Operating Agreement, Canadian storage filled 1524 hm^3 (1236 Kaf) above the TSR by February 2006, remained above the TSR through June, and returned to the TSR in July. Canadian Treaty Storage ended the Operating Year at 373 hm^3 (302.5 Kaf) below the TSR due to provisional and inadvertent draft.

Canadian Entitlement

During the reporting period, the U.S. Entity delivered the Canadian Entitlement to downstream power benefits from the operation of Mica, Duncan and Arrow reservoirs to the Canadian Entity, at existing points of interconnection on the Canada-U.S. border. The amount returned, not including transmission losses and scheduling adjustments, was 535.1 aMW at rates up to 1,218 MW during 1 August 2005 through 31 July 2006, and 488.5 aMW at rates up to 1,244 MW during 1 August 2006 through 30 September 2006.

During the course of the Operating Year, no curtailment of Canadian Entitlement occurred due to transmission constraints, forced outages, or emergencies on either the U.S. or Canadian side of the border.

Treaty Project Operation

At the beginning of the 2005-2006 operating year, 1 August 2005, actual Canadian storage was at 18.8 km^3 (15.2 Maf) or 98.4% full. Canadian storage ended the operating year on 31 July 2006, at 18.6 km^3 (15.0 Maf) or 97.1% full.

The Mica (Kinbasket) reservoir reached a maximum elevation of 750.56 m (2462.5 ft) on 8 August 2005, 3.82 m (12.5 feet) below full pool. Since reaching its peak level, the reservoir continued to draft and departed from normal levels beginning in late summer due to low basin inflow conditions in August and September. As inflows continued to recede throughout the fall and winter period and outflows increased to meet winter load requirements, the reservoir drafted steadily, reaching 735.27 m (2412.3 ft) on 31 December 2005. With reduced generation requirements in early 2006, the reservoir recovered to near normal levels by mid February 2006, however, continued to draft steadily across spring 2006 to reach a minimum elevation of 727.00m (2384.2 ft) on 7 April 2006, 19.9 m (65.2 ft) above empty. The reservoir then refilled across the summer months, ending August 2006 at 751.73 m (2466.3 ft) or 2.03 m (6.6 ft) above the mean elevation for this date.

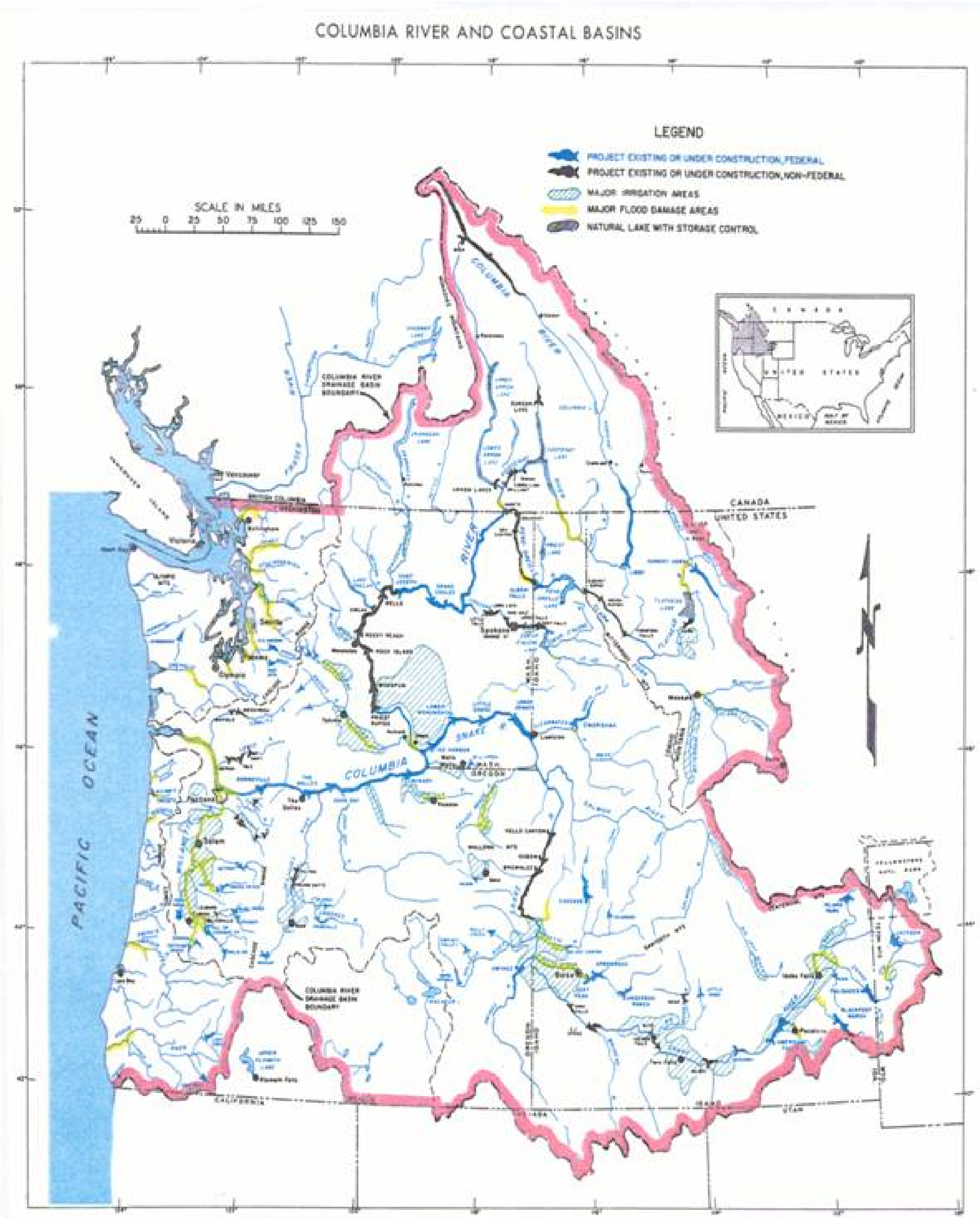
The Arrow reservoir reached a maximum elevation of 434.63 m (1425.9 ft) on 1 July 2005, 5.5 m (18.1 feet) below full pool. Influenced by this low initial level, Arrow reservoir drafted to below normal level, reaching 427.83 m (1403.7 ft) by 31 December 2005, and a minimum elevation of 425.88 m (1397.3 feet) on 31 March 2006, 5.87 m (19.3 ft) above empty. Arrow reservoir refilled to a maximum elevation of 439.82 m (1443.0 ft) on 10 July

2006, 0.31 m (1.0 ft) below full pool. The operation of Arrow Reservoir was modified during the operating year under the NonPower Uses Agreement and the 2006 Summer Storage Agreement (not Treaty). The NonPower Uses Agreement helped to enhance the success of whitefish and rainbow trout spawning and emergence downstream of the Arrow project in British Columbia and to provide additional non-power benefits in the United States (U.S.). The 2006 Summer Storage Agreement helped to reduce inflow into Grand Coulee during the freshet, provide summer flow support for U.S. fisheries, and enhance Arrow reservoir elevations for summer recreation. The agreement did not infringe on Treaty or 1990 Non Treaty Storage Agreement storage operations.

Duncan reservoir reached a maximum elevation of 576.48 m, (1891.4 feet) on 31 July 2005, 0.17 m (0.6 feet) below full pool. From September 2005 through April 2006, Duncan discharge was used to supplement inflow into Kootenay Lake and to provide spawning and incubation flows for fish. The reservoir drafted to a minimum elevation of 546.95 m (1794.5 feet) on 17 April 2006, 0.08 m (0.3 feet) above empty. Reservoir discharge was reduced to a minimum of 3 m^3/s (100 cfs) on 4 May 2006 to initiate reservoir refill. The reservoir refilled to full pool at about 576.7 m (1892 feet) on 23 August 2006.

Libby reservoir reached a maximum elevation on 10 July 2005 of 749.3 m (2458.4 ft). The dam released flow for listed fish needs in the lower Columbia River through July and August and ended August at elevation 743.6 m (2439.5 ft). The reservoir continued to draft through the fall and winter. Libby operated to VARQ (variable flow) flood control storage reservation diagrams in January through April 2006 and the reservoir was at its lowest elevation of 732.8 m (2404.3 ft) at the end of march. During the April through June period, the reservoir was operated to meet the needs of listed sturgeon and listed bull trout in the Kootenai River, while attempting to refill by 30 June for the needs of listed salmon. In mid-May, record high temperature in the Kootenai Valley caused rapid snowmelt that filled Libby reservoir to within 2.74 m (9 ft) from full on 31 May. Heavy thunderstorm activity in early June continued to fill the reservoir. Spill was initiated on 8 June and the maximum outflow from Libby dam was 1,557 m^3/s (55 kcfs) on 19 June when the reservoir filled. The reservoir ended July at elevation 748.9 m (2456.9 ft).

Columbia Basin Map



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Acronyms

AER……………..	Actual Energy Regulation
aMW…………….	Average Megawatts
AOP……………	Assured Operating Plan
B.C. Hydro……	British Columbia Hydro and Power Authority
BiOp……………	Biological Opinion
BPA……………	Bonneville Power Administration
CEEA…………	Canadian Entitlement Exchange Agreement
CEPA…………	Canadian Entitlement Purchase Agreement
cfs………………	Cubic feet per second
CRC…………….	Critical Rule Curve
CRT……………..	Columbia River Treaty
CRITFC…………	Columbia River Inter-Tribal Fish Commission
CRTHC…………	Columbia River Treaty Hydrometeorological Committee
CRTOC…………	Columbia River Treaty Operating Committee
CSPE……………	Columbia Storage Power Exchange
DDPB……………	Determinations Downstream Power Benefits
DFO……………	Department of Fisheries and Oceans
DOP……………	Detailed Operating Plan
FCOP…………	Flood Control Operating Plans
ft………………	feet
hm^3……………	Cubic hectometers
ICF……………	Initial Controlled Flow
IJC………………	International Joint Commission
Kcfs……………	Thousand cubic feet per second
km^3 …………….	Cubic Kilometer (one million cubic meters)
ksfd……………	Thousand second-foot-days (=kcfs x days)
LCA……………..	Libby Coordination Agreement
LOP……………...	Libby Operating Plan
m………………...	Meter

m^3/s……………...	Cubic meters per second
Maf………………	Million acre-feet
MW……………..	Megawatt
NMFS…………..	National Marine Fisheries Service
NOAA F………..	NOAA Fisheries, formerly NMFS
NTSA……………	Non-Treaty Storage Agreement
ORC…………….	Operating Rule Curve
OY………………	Operating Year
PEB……………..	Permanent Engineering Board
PEBCOM……….	PEB Engineering Committee
PNW…………….	Pacific Northwest
TSR……………..	Treaty Storage Regulation
U.S………………	United States
USACE………….	U.S. Army Corps of Engineers
USFWS…………	U.S. Fish and Wildlife Service
VARQ…………..	Variable discharge flood control
WSF…………….	Water Supply Forecast
WUP…………….	Waster use Plan
VRC……………..	Variable Rule Curve
WY………………	Water Year

I - INTRODUCTION

This annual Columbia River Treaty (CRT) Entity Report is for the 2006 water year (WY), 1 October 2005 through 30 September 2006, with additional information on the operation of Mica, Arrow, Duncan, and Libby reservoirs during the reservoir system operating year, 1 August 2005 through 31 July 2006. The power and flood control effects downstream in Canada and the U.S. are described. This report is the 40th of a series of annual reports covering the period since the ratification of the Columbia River Treaty (CRT) in September 1964.

Duncan, Arrow, and Mica reservoirs in Canada and Libby reservoir in the U.S. were constructed under the provisions of the CRT of January 1961. Treaty storage in Canada (Canadian storage) is operated for the purposes of flood control and increasing hydroelectric power generation in Canada and the U.S. In 1964, the Canadian and the U.S. governments each designated an Entity to formulate and carry out the operating arrangements necessary to implement the CRT. The Canadian Entity for these purposes is B.C. Hydro. The Canadian Entity for Entitlement Return is the government of the Province of British Columbia. The U.S. Entity is the Administrator/Chief Executive Officer of BPA and the Division Engineer of the Northwestern Division, U.S. Army Corps of Engineers (USACE).

The following is a summary of key features of the CRT and related documents:

1. Canada was to provide 19.12 km^3 (15.5 Maf) of usable storage. This has been accomplished with 8.63 km^3 (7.0 Maf) in Mica, 8.78 km^3 (7.1 Maf) in Arrow, and 1.73 km^3 (1.4 Maf) in Duncan.
2. For the purpose of computing downstream power benefits the U.S. base system hydroelectric facilities will be operated in a manner that makes the most effective use of the improved streamflow resulting from operation of the Canadian storage.
3. The U.S. and Canada are to share equally the downstream power benefits generated in the U.S. resulting from operation of the Canadian storage.
4. The U.S. paid Canada a lump sum of the $64.4 million (U.S.) for one half of the present worth of expected future flood control benefits in the U.S. to September 2024, resulting from operation of the Canadian storage.
5. The U.S. has the option of requesting the evacuation of additional flood control space above that specified in the CRT, for a payment of $1.875 million (U.S.) for each of the first four requests for this "on-call" storage. None have been used to date.
6. The U.S. had the option (which it exercised) to construct Libby Dam with a reservoir that extends 67.6 kilometers (42 miles) into Canada and for which Canada agreed to make the land available.
7. Both Canada and the U.S. have the right to make diversions of water for consumptive uses. In addition, since September 1984, Canada has had the option of making, for power purposes, specific diversions of the Kootenay River into the headwaters of the Columbia River.

8. Differences arising under the Treaty which cannot be resolved by the two countries may be referred to either the International Joint Commission (IJC) or to arbitration by an appropriate tribunal.

9. The Treaty shall remain in force for at least 60 years from its date of ratification, 16 September 1964.

10. In the Canadian Entitlement and Purchase Agreement (CEPA) of 13 August 1964, Canada sold its entitlement to downstream power benefits (Canadian Entitlement) to the Columbia Storage Purchase Exchange (CSPE - a consortium of U.S. utilities) for 30 years beginning at Duncan on 1 April 1968, Arrow on 1 April 1969, and Mica on 1 April 1973. That sale has now expired and all Canadian Entitlement has reverted to B.C. provincial ownership and is being either delivered to the Canada-U.S. border or sold directly in the United States.

11. Canada and the U.S. are each to appoint Entities to implement Treaty provisions and are to jointly appoint a joint Permanent Engineering Board (PEB) to review and report on operations under the CRT.

II - TREATY ORGANIZATION

Entities

There was one meeting of the CRT Entities (including the Canadian and U.S. Entities and Entity Coordinators) during the year on the morning of 8 February 2006 in Portland Oregon. The members of the two Entities at the end of the period of this report were:

UNITED STATES ENTITY
Mr. Stephen J. Wright, Chairman
Administrator & Chief Executive Officer
Bonneville Power Administration
Department of Energy
Portland, Oregon

Brigadier General Gregg F. Martin, Member
Division Engineer
Northwestern Division
U.S. Army Corps of Engineers
Portland, Oregon

CANADIAN ENTITY
Mr. Robert G. Elton, Chair
President & Chief Executive Officer
British Columbia Hydro and Power Authority
Vancouver, British Columbia

The Entities' have designated alternates to act on behalf of the primaries in their absence; appointed in the U.S. by a Memorandum of Agreement between Bonneville and Corps of Engineers, and in Canada by the B.C. Hydro Board of Directors. Mr. Wright's alternate is Bonneville Deputy Administrator, Steven G. Hickok; Mr. Elton's Deputy is Ms. Dawn Farrell; and BG Martin's alternate is COL Randall L. Fofi.

The Entities have appointed Coordinators, Secretaries, and two joint standing committees to assist in CRT implementation activities that are described in subsequent paragraphs. The primary duties and responsibilities of the Entities as specified in the CRT and related documents are to:

1. Plan and exchange information relating to facilities used to obtain the benefits contemplated by the CRT.
2. Calculate and arrange for delivery of hydroelectric power to which Canada is entitled and the amounts payable to the U.S. for standby transmission services (latter is no longer in effect).
3. Operate a hydrometeorological system.
4. Assist and cooperate with the PEB in the discharge of its functions.
5. Prepare hydroelectric and Flood Control Operating Plans (FCOPs) for the use of Canadian storage.
6. Prepare and implement Detailed Operating Plans (DOPs) that may produce results more advantageous to both countries than those that would arise from operation under Assured Operating Plans (AOPs).

Additionally, the CRT provides that the two governments, by exchange of diplomatic notes, may empower or charge the Entities with any other matter coming within the scope of the CRT.

Entity Coordinators and Secretaries

The Entities have appointed Coordinators from members of their respective staffs to help manage and coordinate CRT related work, and Secretaries to serve as information focal points on all CRT matters within their organizations. Those personnel are:

UNITED STATES ENTITY
COORDINATORS
Stephen R. Oliver
Vice President, Generation Supply
Bonneville Power Administration
Portland, Oregon

Karen Durham-Aguilera
Director, Civil Works & Management
Northwestern Division
U.S. Army Corps of Engineers
Portland, Oregon

CANADIAN ENTITY
COORDINATOR
Renata Kurschner
Senior Manager
Integrated Portfolio
Generation Management
B.C. Hydro
Burnaby, British Columbia

Renata Kurschner replaced Ken Spafford as Canadian Coordinator on 1 July 2006.

UNITED STATES ENTITY
SECRETARY
Dr. Anthony G. White
Regional Coordination
Power and Operations Planning
Bonneville Power Administration
Portland, Oregon

CANADIAN ENTITY
SECRETARY
Douglas A. Robinson
Integrated Portfolio Management
Generation
B.C. Hydro
Burnaby, British Columbia

Columbia River Treaty Operating Committee

The Columbia River Treaty Operating Committee (CRTOC) was established in September 1968 by the Entities, and is responsible for preparing and implementing operating plans as required by the CRT, making studies and otherwise assisting the Entities as needed. The CRTOC consists of eight members as follows:

UNITED STATES SECTION
Richard M. Pendergrass, BPA, Alt. Chair
James D. Barton, USACE, Alt. Chair
Cynthia A. Henriksen**, USACE
John M. Hyde, BPA

CANADIAN SECTION
Kelvin Ketchum, B.C. Hydro, Chair
Dr. Thomas K. Siu, B.C. Hydro
Gillian Kong*, B.C. Hydro
Herbert Louie, B.C. Hydro

* Ms. Kong replaced Allan Woo as Canadian Section Member on 23 September 2005.

** Ms. Cathy Hlebechuk was appointed as a member on 3 October 2005. Ms. Henriksen resumed her duties as a member in January 2006.

The CRTOC met six times during the reporting period to exchange information, approve work plans, and discuss and agree on operating plans and issues. The meetings were held every other month alternating between Canada and the U.S. During the period covered by this report, the CRTOC:

- Coordinated the operation of the CRT storage in accordance with the current hydroelectric operating plans and FCOPs;
- Reviewed scheduled delivery of the Canadian Entitlement according to the CRT and related agreements;
- Completed studies and documents for the 2010-11 AOP/Determination of Downstream Power Benefits (DDPB);
- Completed the 1 August 2006 through 31 July 2007 DOP;
- Completed one supplemental operating agreement for Canadian storage.
- Implemented the Libby Coordination Agreement and monitored downstream Canadian power effects from Variable Q flood control operation at Libby;
- Updated Appendix B, the Libby Operating Plan, of the Libby Coordination Agreement on 21 April 2006;
- Updated 70-year flood control rule curves for AOP planning studies; and
- Briefed the Permanent Engineering Board and Engineering Committee on Entity activities.

These aspects of the CRTOC's work are described in following sections of this report, which have been prepared by the CRTOC with the assistance of others.

Pictured from left to right: Tom Siu (B.C. Hydro, Member), John Hyde (BPA Member), Cynthia Henriksen (USACE, Member), James Barton (USACE, U.S. Alt.-Chair), Rick Pendergrass (BPA, U.S. Alt.-Chair), Kelvin Ketchum (B.C. Hydro, Canadian Chair), Doug Robinson (B.C. Hydro, Canadian Entity Secretary), Herbert Louie (B.C. Hydro, Member), Gillian Kong (B.C. Hydro Member), Tony White (BPA U.S. Entity Secretary)

Columbia River Treaty Hydrometeorological Committee

The Hydrometeorological Committee was established in September 1968 by the Entities and is responsible for planning and monitoring the operation of data facilities in accord with the Treaty and otherwise assisting the Entities as needed. The Committee consists of four members as follows:

UNITED STATES SECTION	CANADIAN SECTION
Nancy L. Stephan, BPA Co-Chair	Stephanie Smith, B.C. Hydro, Chair
Peter Brooks*, USACE Co-Chair	Doug McCollor**, B.C. Hydro, Member

*Cynthia Henriksen was appointed U.S. Co-Chair per United States Entity letter dated 3 October 2005. Peter Brooks resumed Co-Chair duties in January of 2006.

** Doug McCollor was appointed Canadian Member per B.C. Hydro letter dated 29 November 2005.

The Columbia River Treaty Hydrometeorologic Committee (CRTHC) met twice during the operating year. The first meeting was held 9 February 2006 at the Bonneville Power Administration's Headquarters in Portland, Oregon. The second meeting was held on 15 June 2006 at the US Army Corps of Engineer's offices also in Portland, Oregon.

The problem of inconsistencies due to calculated Canadian storage values from CROHMS not matching the data being sent directly to agencies in the U.S. continued to be an issue. At the July CRTOC meeting, B.C. Hydro reported that for Arrow reservoir, the DOP storage vs. elevation table is different from the B.C. Hydro table that is used in real-time. The B.C. Hydro real-time table reflects the separation of the reservoir into two lakes at lower reservoir elevations. The Hydromet Committee conducted a review of what is the source of the discrepancies and recommended that the B.C. Hydro tables continue to be used in real-time, but that both storage and elevation values be provided to the U.S. agencies in near-real-time to reduce discrepancies.

The Committee was involved in the review of several sets of new water supply forecasting procedures throughout the year. The first new equations were developed by the USACE for Dworshak. The development of these procedures used the Principle Component Analysis, similar to the original procedures, but included additional years to the data set and made minor adjustments to the station selections. The CRTHC recommended the new Dworshak equations to the CRTOC at their 15 November 2006 meeting. The December through June equations were approved at the CRTOC November meeting, however, due to some confusion, the November equation was not approved by the CRTOC until the 7 March 2006 meeting.

In addition to recommending the adoption of the new forecast equations for Dworshak, the CRTHC also recommended at the 7 March 2006 CRTOC meeting that the Cross-Validation Standard Error (CVSE) be adopted for Treaty calculations rather than the Standard Error which had been frequently used in the past. The CRTHC advised that the CVSE was more representative of the variability and error associated with the forecast equations in real-time applications. The CRTHC also recommended that for equations developed on 40-50 years of data, the 1.68 factor be used to calculate the 95% confidence level, rather than a factor of 1.645 which would be used with an infinite number of data points. The CRTOC adopted both these recommendations at the 7 March meeting.

Toward the end of the year, the new Canadian water supply forecast equations were completed for Mica, Arrow and Duncan. B.C. Hydro took a novel approach in developing its statistical water supply forecast equations. The new approach looked at developing forecast equations for individual monthly runoff volumes as opposed to the traditional approach of a single equation for the seasonal volume at a given forecast date. The objective in developing their forecast equations this way was to provide not only a seasonal volume but also a forecast for individual monthly volumes and associated uncertainties. B.C. Hydro also developed early season forecast equations for use in November and December. The early season forecast equations were developed only to provide a seasonal volume, while the January – July equations provided the monthly volumes which are then summed to seasonal volumes. The CRTHC recommended the November through July forecast equations and their associated CVSEs to the CRTOC at their 12 September meeting. The CRTOC approved the December through July equations and the new CVSEs.

Permanent Engineering Board

Provisions for the establishment of the Permanent Engineering Board (PEB) and its duties and responsibilities are included in the CRT and related documents. The members of the PEB are presently:

UNITED STATES SECTION	CANADIAN SECTION
Stephen L. Stockton, Chair Washington, D.C.	Tom Wallace, Chair Ottawa, Ontario
Edward Sienkiewicz, Member Newberg, Oregon	Tim Newton, Member Vancouver, British Columbia
Robert A. Pietrowsky, Alternate-Nominee Washington, D.C.	James Mattison, Alternate Victoria, British Columbia
George E. Bell, Alternate Portland, Oregon	David E. Burpee, Alternate Ottawa, Ontario
Jerry W. Webb, Secretary Washington, D.C.	Eve Jasmin, Secretary Ottawa, Ontario

Dr. Pietrowsky, Alternate-Nominee, was nominated to replace Alternate- nominee Earl Eiker.

Under the CRT, the PEB is to assemble records of flows of the Columbia River and the Kootenay River at the international boundary. The PEB is also to report to both governments if there is substantial deviation from the hydroelectric or flood control operating plans, and if appropriate, include recommendations for remedial action. Additionally, the PEB is to:

- Assist in reconciling differences that may arise between the Entities.
- Make periodic inspections and obtain reports as needed from the Entities to assure that CRT objectives are being met.

- Prepare an annual report to both governments and special reports when appropriate.
- Consult with the Entities in the establishment and operation of a hydrometeorological system.
- Investigate and report on any other CRT related matters at the request of either government.

The Entities continued their cooperation with the PEB during the past year by providing copies of Entity agreements, operating plans, Operating Committee agreements, updates to hydrometeorological documents, personnel appointments, pertinent correspondence, and the annual Entity report to the Board for their review. The annual joint meeting of the PEB and the Entities was held on 8 February 2006 in Portland, Oregon, where the Entities briefed the PEB on the preparation and implementation of operating plans, the delivery of the Canadian Entitlement, and other topics requested by the Board. The PEB and PEBCOM asked the Entities to explore options for a web page repository of historic Treaty-related documents for their use.

PEB Engineering Committee

The PEB has established a PEB Engineering Committee (PEBCOM) to assist in carrying out its duties. The members of PEBCOM at the end of the period of this report were:

UNITED STATES SECTION	CANADIAN SECTION
Jerry W. Webb, Chair Washington, D.C.	Roger S. McLaughlin, Chair Victoria, British Columbia
Michael S. Cowan, Member Lakewood, CO	Eve Jasmin, Member Ottawa, Ontario
Kamau B. Sadiki, Member Washington, D.C.	Ivan Harvie, Member Calgary, Alberta
D. James Fodrea, Member Boise, ID	Dr. G. Bala Balachandran, Member Victoria, British Columbia
	David E. Burpee, Member Ottawa, Ontario

Mr. Sadiki was replaced for three months by John O. Johannis, who subsequently changed positions, followed by Mr. Sadiki's reappointment.

The PEBCOM met with the Operating Committee on 26 October 2005 in Victoria, British Columbia.

International Joint Commission

The International Joint Commission (IJC) was created under the Boundary Waters Treaty of 1909, between Canada and the U.S. Its principal functions are rendering decisions on the use of boundary waters, investigating important problems arising along the common frontier not necessarily connected with waterways, and making recommendations on any question referred to it by either government. If the Entities or the PEB cannot resolve a dispute concerning the CRT, that dispute may be referred to the IJC for resolution.

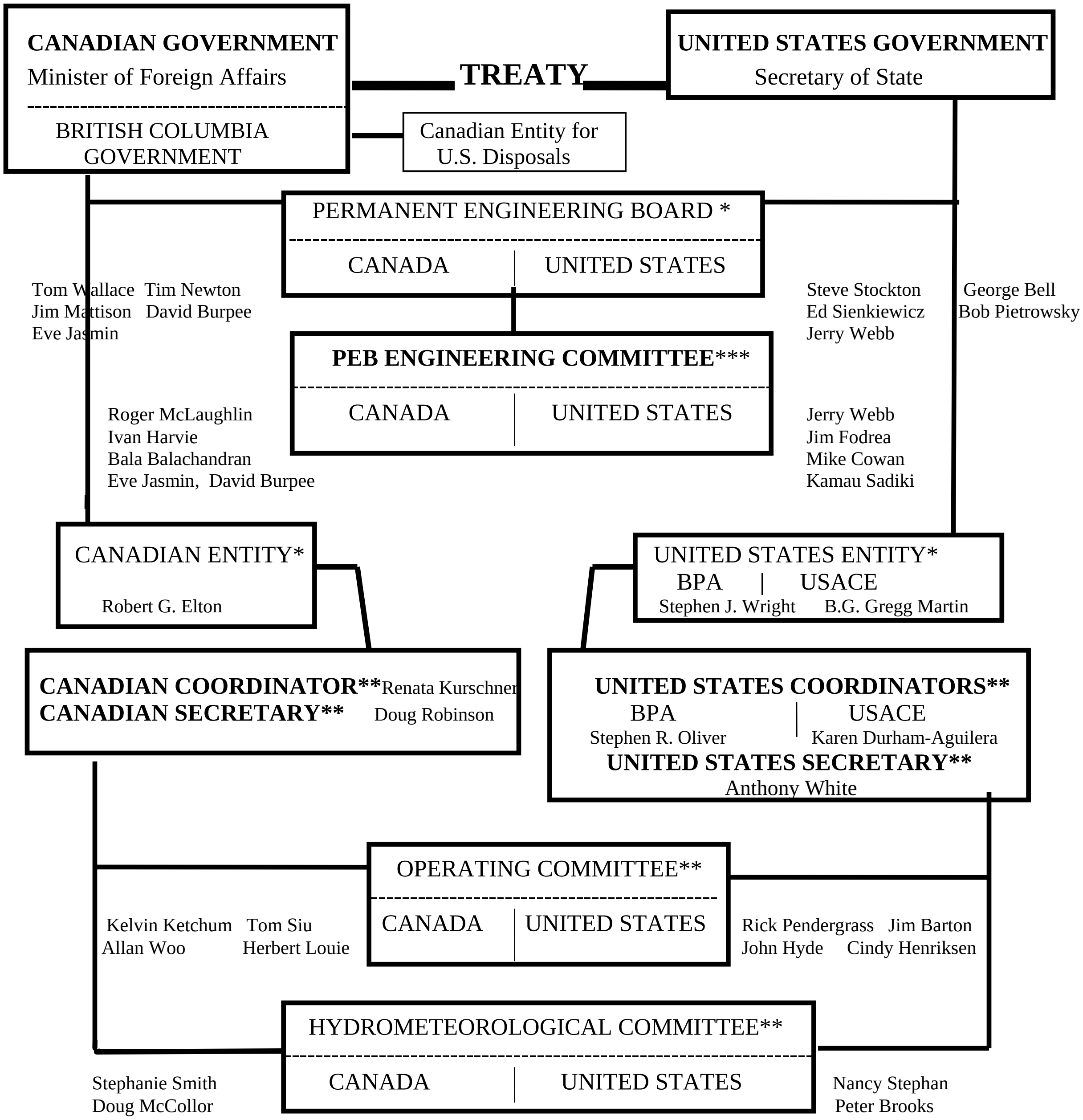
The IJC has appointed local Boards of Control to insure compliance with IJC orders and to keep IJC informed. There are three such boards west of the continental divide. These are the International Kootenay Lake Board of Control, International Columbia River Board of Control, and International Osoyoos Lake Board of Control. The Entities and IJC Boards conducted their CRT activities during the period of this report so that there was no known conflict with IJC orders or rules.

The U.S. Section Chair is Dennis L. Schornack of Williamston, MI. The Canadian Section Chair is The Right Honorable Herb Gray of Ottawa, Canada. Canadian members are Mr. Robert Gourd, Montreal, QUE., and Mr. Jack P. Blaney, Vancouver, B.C. U.S. members are Ms. Irene B. Brooks, Seattle, WA, and Mr. Allen I. Olson, Edina, MN.

Presentations

During the period covered by this report, CRT personnel made presentations about the history, structure, operations, challenges and communications associated with the CRT to visitors and inquirers from professional, environmental, academic and civic groups; government of India; Northwest Power Planning Council staff; Columbia Basin Trust and attendees at one of its conferences; and the Legislative Council on River Governance. An article was published in the September 2005 journal ***Hydro Review*** outlining the basic elements of Treaty involvement in the management processes of the Columbia River system.

Columbia River Treaty Organization



*** ESTABLISHED BY TREATY**
**** ESTABLISHED BY ENTITY**
***** ESTABLISHED BY PEB**

III - OPERATING ARRANGEMENTS

Power and Flood Control Operating Plans

The CRT requires that the reservoirs constructed in Canada be operated pursuant to flood control and hydroelectric operating plans developed hereunder. Annex A of the CRT:

(1) Stipulates that the U.S. Entity will submit FCOPs;

(2) States that the Canadian Entity will operate in accordance with flood control storage diagrams or any variation which the Entities agree will not reduce the desired aim of the flood control plan; and

(3) Provides for the development of assured hydroelectric operating plans for Canadian storage for the sixth succeeding year of operation.

Article XIV.2.k of the CRT provides that a DOP be developed that may produce results more advantageous than the AOP. The Protocol to the CRT provides further detail and clarification of the principles and requirements of the CRT.

The "Principles and Procedures for the Preparation and Use of Hydroelectric Operating Plans for Canadian Treaty Storage", signed December 2003 (as amended), together with the "Columbia River Treaty Flood Control Operating Plan" dated May 2003 (as revised), establish and explain the general criteria used to develop the AOP and DOP and operate CRT storage during the period covered by this report.

The planning and operation of CRT Storage as discussed on the following pages is for the operating year, 1 August 2005 through 31 July 2006. The operation of Canadian Storage was determined by the 2005-06 DOP and supplemental operating agreements. The DOP required a semi-monthly Treaty Storage Regulation (TSR) study to determine end-of-month storage obligations prior to any supplemental operating agreements. The TSR included all operating criteria from, and was based on, the Step I Joint Optimum Power Hydroregulation Study from the 2005-2006 AOP, with agreed changes. Most of the hydrographs and reservoir charts in this report are for a 14-month period, August 2005 through September 2006.

Assured Operating Plans

During the reporting period, the Entities completed the 2010-11 AOP/DDPB using the load and resource streamline method developed for the prior AOP/DDPB and the procedures described in the 2003 Principles and Procedures document.

The 2010-11 AOP establishes ORCs, Critical Rule Curves (CRCs), Mica and Arrow Project Operating Criteria, and other operating criteria included in the Step I Joint Optimum Power Hydroregulation Study, to guide the operation of Canadian storage. The ORCs were derived from CRCs, Assured Refill Curves, Upper Rule Curves (Flood Control), Variable Refill Curves and Operating Rule Curve Lower Limits, consistent with flood control requirements, as described in the 2003 Principles and Procedures document. They provide guidelines for draft and refill under a wide range of water conditions. The Flood Control Rule Curves conform to the 2003 FCOP, and are used to define maximum reservoir levels for the operation of Canadian storage. The 2010-11 AOP uses the 5.03/4.44 km^3 (4.08/3.6 Maf)

Mica/Arrow flood control allocation. The CRCs are used to apportion draft below the ORC when the TSR determines additional draft is needed to meet the Coordinated System firm energy load carrying capability.

Determination of Downstream Power Benefits

For each operating year, the Determination of Downstream Power Benefits (DDPB) resulting from Canadian Treaty storage is made in conjunction with the AOP according to procedures defined in the CRT, Annexes, and Protocol. The total CRT downstream power benefits as a result of the operation of Canadian storage for operating years 2005-2006 and 2006-2007 were determined to be 1,070.3 MW and 977.0 MW average annual usable energy and 2,436.9 MW and 2,488.6 MW dependable capacity, respectively.

In conjunction with the 2010-11 AOP, the Entities completed the 2010-11 DDPB which showed a decrease in the downstream power benefits compared to the prior DDPB. The total CRT downstream power benefits as a result of the operation of Canadian storage for the 2010-11 operating year was determined to be 1,071.5 MW average annual usable energy and 2,632.9 MW dependable capacity.

Canadian Entitlement

For the period 1 August 2005 through 31 July 2006, this amount, before losses, was 535.1 aMW of energy, scheduled at rates up to 1,218 MW, and from 1 August 2006 through 30 September 2007, the amount, before losses, was 488.5 aMW of energy, scheduled at rates up to 1,244 MW. The Canadian Entitlement obligation was determined by the 2005-2006 and 2006-07 AOP/DDPB’s.

During the course of the Operating Year, there were no curtailments of Canadian Entitlement due to transmission constraints or emergencies on either the U.S. or Canadian side of the border.

Detailed Operating Plans

During the period covered by this report, the Operating Committee used the 1 August 2005 through 31 July 2006 "Detailed Operating Plan for Columbia River Treaty Storage", dated June 2005, and the 1 August 2006 through 31 July 2007 DOP, dated May 2006, to guide Canadian storage operations. These DOPs established criteria for determining the ORCs, proportional draft points, and other operating data for use in actual operations. The 2005-2006 DOP was based on the 2005-2006 AOP. The AOP06 loads and resources, rule curves, and other operating criteria with agreed changes for both Canadian and U.S. projects, were used to develop the Treaty Storage Regulation (TSR) studies for implementation of Canadian Storage operations. The changes were mainly updates to flood control rule curves and use of the 5.03 km^3/4.44 km^3 (4.08/3.06 Maf) Mica/Arrow flood control allocation, updated hydro-independent data, the operation of the Brownlee project, and updating Grand Coulee pumping estimates. The 2006-2007 DOP was based on the 2006-2007 AOP with changes similar to the 2005-2006 DOP, except that the 2006-07 AOP did include the 5.03 km^3/4.44 km^3 (4.08/3.6 Maf) Mica/Arrow flood control allocation.

The 2006-2007 AOP included a flood control allocation of 6.29 km^3 /m (5.1 Maf) in Arrow and 2.57 km3/m (2.08 Maf) in Mica. B.C. Hydro requested a reallocation of the flood control space to operate to a 5.03/4.43 km^3/m (4.08/3.6 Maf) Mica/Arrow allocation. A process to implement the flood control reallocation was agreed to by the Committee on 28 June 2004 and 13 July 2005.

The Treaty Storage Regulation (TSR) studies were updated twice monthly throughout the operating year, and together with supplemental operating agreements, defined the end-of-month draft rights for Canadian storage. The Variable Rule Curves (VRCs) and flood control requirements subsequent to 1 January 2006 were determined on the basis of seasonal volume runoff forecasts during actual operation. The VRC calculations for Canadian reservoirs and Libby for the 2005-2006 operating year are shown in Tables 2 through 5. The tabular calculation in Table 5 for Libby's VRCs was used in the TSR study only and is not used in real time operations.

The Operating Committee directed the regulation of the Canadian storage, on a weekly basis throughout the year, in accordance with the applicable DOPs and supplemental operating agreements made there under.

Libby Coordination Agreement

During the period covered by this report, the Libby Coordination Agreement (LCA) procedures allowed the Canadian Entity to provisionally draft Arrow reservoir and exchange power with the U.S. Entity, and required delivery to the U.S. Entity of one (1) aMW, shaped flat, over the entire Operating Year.

The Libby Operating Plan (LOP) was updated once during the reporting period in response to a new USFWS Biological Opinion dated 18 February 2006. Because of the new BiOp, the LOP was updated 21 April 2006 to reflect new sturgeon tier volumes, variable end of December flood control draft, and bull trout minimum flow.

Entity Agreements

During the period covered by this report, three joint U.S.-Canadian arrangements were approved by the Entities:

Date Agreement Signed by Entities	Description
6 February 2006	Columbia River Treaty Entity Agreement on the Assured Operating Plan and Determination of Downstream Power Benefits for the 2010-11 Operating Year
22 June 2006	Columbia River Treaty Entity Agreement on the Detailed Operating Plan for Columbia River Storage 1 August 2006 through 31 July 2007.
26 June 2006	Columbia River Treaty Entity Agreement determining no adverse Treaty impacts of BPA-B.C. Hydro storage in non-Treaty space for 25 May – 30 September 2006.

Operating Committee Agreements

During the period covered by this report, the Operating Committee approved the following joint U.S. - Canadian storage agreement:

Date Signed by Committee	Description	Authority
16 December 2005	Columbia River Treaty Operating Committee Agreement on the Operation of Treaty Storage for Nonpower Uses for the Period 1 December 2005 through 31 July 2006	Detailed Operating Plan, 1 August 2005 through 31 July 2006, approved June 2005 and dated 20 June 2005

Long Term Non-Treaty Storage Contract

An Entity agreement dated 9 July 1990 approved the contract between B.C. Hydro and BPA relating to the initial filling of non-Treaty storage, coordinated use of non-Treaty storage, and Mica and Arrow refill enhancement. The Operating Committee, in accordance with that agreement, monitored the storage operations made under this agreement throughout the operating year to insure that they did not adversely impact operation of CRT storage. The Entity agreement dated 28 June 2002, gave approval for B.C. Hydro and BPA to extend the expiration date of the contract by one year, from 30 June 2003 to 30 June 2004, which was done. Two Mid-Columbia parties, Eugene Water and Electric Board and Tacoma Utilities, elected to extend their NTSA Agreement with BPA for the same one-year period.

No further extension of the contract was completed, however, and as per contract terms, release rights under the Non-Treaty Storage Agreement terminated effective 30 June 2004. While the parties anticipate negotiating a replacement coordination agreement to make use of the non-Treaty storage space available in the Mica and Arrow reservoirs, low NTSA storage levels, low runoff conditions and high market prices during 2004-05, provided little economic incentive to expedite the negotiations. However, good water conditions during the first half of 2006 resulted in significant progress being made towards refilling both parties' accounts. At the end of September 2006 the B.C. Hydro account stands at 78% of full, and BPA account stands at 46% of full. In the absence of a new agreement, the extended Provisions of the 1990 Agreement require that active Non-Treaty Storage Space in Mica be refilled prior to 30 June 2011.

IV - WEATHER AND STREAMFLOW

Weather

A wetter and cooler than normal June 2005 transitioned to drier and warmer conditions toward the middle of July, as the storm track lifted north of the Canada-U.S. border. This led to a drier start to August in the U.S. basins but allowed for weak weather systems to impact the Canadian districts. Later in the month, a low pressure trough from the Gulf of Alaska moved into the Columbia Basin and supplied moderate rain to parts of the Basin. Precipitation for August averaged 63% of normal at Columbia above Grand Coulee, 62% of normal at the Snake River above Ice Harbor, and 88% of normal at Columbia above The Dalles. August was warmer than normal, region-wide, with some coastal spots tying high temperature records: Sea-Tac on 14 August, at 31.1 °C (88 °F), Astoria on 25 August, with 29.4 °C (85 °F). A cool trough around mid month, allowed some low temperatures to break records too: Eugene, on 10 August, at 6.7°C (44 °F), Kalispell, 13 August, at 1.1 °C (34 °F). Overall the region departed +0.8 °C (+1.4 °F) from the 1971-2000 normal.

As September opened, the weather pattern favored a low pressure trough over western Canada, carried over from part of August. This brought frequent precipitation across the B.C. tier districts, resulting in 169% of normal precipitation at Columbia above Grand Coulee, and 128% of normal at Columbia above The Dalles. The rest of the Basin was a little too close to high pressure to register above normal rainfall: The Snake River above Ice Harbor saw 69% of normal precipitation. A low pressure trough, at this time of year, translates to largely below normal temperatures region-wide. Indeed, the region departed 0.8 °C (-1.4 °F) from normal. As the month closed, the low pressure trough moved slowly to the west thus increasing a moist southwesterly flow into the region. As a result, precipitation sharply increased through October. Precipitation was 162% of normal at Columbia above Grand Coulee, 129% of normal at Columbia above The Dalles, and 120% of normal at the Snake River above Ice Harbor. Still on the cool side, departures bottomed out at -0.8 °C (-1.5 °F). As October closed and November began, the low pressure trough had weakened and moved off further to the west. The ridge of high pressure that replaced it brought drier weather for the first half of November.

The ridge was part of a split flow pattern just offshore. As we entered November, the northern branch of this split sent storms far to the north while the southern branch detoured them across southern Oregon through California. A consolidation of the split flow occurred about mid month and that lead to a wet, tropically-fed weather system to deliver significant rain and snow into the region during the last half of the month. November precipitation was 72% of normal at Columbia above Grand Coulee, 50% of normal at the Snake River above Ice Harbor, and 60% of normal at Columbia above The Dalles. Since most of the storms cut across the southern U.S. districts, we found the coolest temperature there and these tended to skew the overall regional temperature profile: -1.1 °C (-1.9 °F) departure from normal. The split flow continued into December, anchored mainly by high pressure.

The high weakened quickly by mid month and opened the door to a strong jet stream that stretched from Asia to the U.S. west coast. The landfall position of the storm track was such as to keep temperatures (and snow levels) low. For the month, Columbia above Grand Coulee received 83% of normal precipitation, Columbia above The Dalles, 115% of normal, and Snake River above Ice Harbor saw 183% of normal precipitation, a great indication that the storm track literally bisected the Basin. As a result of the precipitation onslaught, daily records were broken at several places: Astoria on 23 December, 6.43 cm (2.53”), Portland on 28 °December, 2.39 cm (0.94”), 30 °December, Pendleton 2.16 cm (0.85”), Troutdale, 3.66 cm (1.44”), Eugene, 6.22 cm (2.45”), and Astoria, 5.87 cm (2.31”). The region departed -0.4 °C (-0.7 °F) from normal, yet a closer look at this “normal” signal reveals a range of -2.9 to 5.3 °C (-5.3 to 9.5 °F). On the high end, new high temperatures were established at Medford and Astoria, each with 16.1 °C (61 °F), and 15.6 °C (60 °F) at both Salem and Eugene. New low temperature records were broken at Kalispell with -28.3 °C (-19 °F), and -26.7 °C (-16 °F) at Missoula, both early in the month and within a brief high pressure regime. The strong jet stream pattern carried into the New Year.

As a result, the January 2006 precipitation was very impressive, at 160% of normal Columbia above Grand Coulee, 159% of normal at Columbia above The Dalles, and 159% of normal at the Snake River above Ice Harbor. Many daily precipitation records were broken due to this pattern: 3.38 cm (1.33”) at Sea-Tac Airport, 7.39 cm (2.91”) at Astoria, both on the 5th; Olympia on 10 January, 3.96 cm (1.56”), and again at Olympia on 16 January, 3.96 cm (1.56”). Eugene broke a daily record on 17 January, accumulating 6.02 cm (2.37”). Portland and Olympia broke daily records on 29 January: 2.31 and 5.66 cm (0.91” and 2.23”), respectively. With the favorable westerly flow, lower elevation temperatures remained mild, even though snow levels remained seasonably low. High temperature records for the month included Sea-Tac, with 14.4 °C (58 °F), 10.0 °C (50 °F) at Spokane, and 17.8 °C (64 °F) at Astoria. The overall, regional temperature departure was +4.2 °C (+7.5 °F), even with those lower snow levels! In comparison, and with a relaxation of the storm track, February proved to be a little different.

As higher pressure moved toward western Canada, and low pressure moved off well to the east, the region began drying and cooling in February. Early in the month, as the high caused some offshore flow, we saw a daily temperature record at Medford, with 21.1 °C (70 °F). But, in the chilly northerly flow, east of the high, other records were set: on the cool side. These included -10.6, -13.9, and -16.1 °C (13, 7, and 3 °F) at Redmond, -5.6 °C (22 °F) at Olympia, -15 °C (5 °F) at Yakima, -7.8 °C (18 °F) at Salem and Eugene, -7.2 °C (19 °F) at Astoria, and -5.6 °C (22 °F) at Portland. Since mostly high pressure dominated the month, precipitation fell back from normal, boosted by a late month surge of moisture in a northwesterly flow. This kept snow levels low, again. February precipitation was 102% of normal at Columbia above Grand Coulee, 83% of normal at Columbia above The Dalles, and 68% of normal at the Snake River above Ice Harbor. So, for February, the northern basins benefited. That was to change in March as the high moved off to the east and far to the west, leaving room for low pressure to develop off the southern and northern California coast.

The position of the low meant that most of the precipitation would impact the southern basins. For March, precipitation was only 71% of normal at Columbia above Grand Coulee, 95% of normal at Columbia above The Dalles, and 130% of normal at the Snake River above Ice Harbor. Daily precipitation records were broken at Redmond with 1.24 cm (0.49”), 1.85 cm (0.73”) at Pendleton, and 2.46 cm (0.97”) at Walla Walla. March temperatures, based on the 31-station, Pacific Northwest station index, were cooler than normal by 0.5 °C (0.9 °F). March had only one record low temperature: -12.2 °C (10 °F) at Redmond. The slightly cooler than normal pattern was briefly interrupted in April as more of a southerly flow dominated the region.

In April, the offshore low moved further to the south and west, allowing high pressure to build just west of the Rockies. Thus, the southerly flow had a strong corridor through which it delivered abundant precipitation, largely through Idaho, western Montana, and up into B.C. As such, April precipitation was 150% of normal at Columbia above Grand Coulee, 165% of normal at Columbia above The Dalles, and 139% of normal at the Snake River above Ice Harbor. Several daily precipitation records were broken during the month. Most notably, they included 1.43 and 2.77 cm (0.58” and 1.09”) at Butte, 4.45 cm (1.75”) at Missoula, 1.14 cm (0.45”) at Idaho Falls, and 0.84 cm (0.33”) at Yakima. In terms of temperature, record daily highs were hit at Astoria, with 22.8 °C (73 °F), and Seattle with 22.2 °C (72 °F). Record daily low temperatures included 2.2 °C (36 °F) at Seattle and -1.7 °C (29 °F) at Pendleton. Overall, the region departed -0.5 °C (-0.9 °F) from normal relative to the 1971-2000 normals. Warmer weather followed in May, especially during the middle to latter half of the month.

In a continued deep southerly flow, weather systems persisted in bringing moderate to regionally heavy precipitation in May. At Columbia above Coulee, precipitation was 194% of normal for the month; at Columbia above The Dalles, 150% of normal; and at the Snake River above Ice Harbor, 194% of normal. Again, numerous daily records were set, including Lewiston, with 1.52 cm (0.60”), Spokane, 2.24 cm (0.88”), Portland with 1.50 cm (0.59”), and Salem with 1.68 cm (0.66”). Warmer temperatures were the result of the high pressure moving to the west, and also forcing the offshore low to move to its west. The regional temperature profile ended at a 1.0 °C (+1.8 °F) departure, with impressive warmth at several inland western valley sites. Portland broke a record daily high of 35.0 °C (95 °F), as did Medford. Sea-Tac broke a daily record of 31.7 °C (89 °F), and Hillsboro set a record at 34.4 °C (94 °F). The seasonal snowpack accumulation for the Columbia Basin above the Dalles for the January through May period is shown in Chart 1. Warmer than normal weather continued into June.

With high pressure largely in control, and with a stubborn southerly flow still active, June’s weather was mainly wet and warm. Precipitation was 113% of normal at Columbia above Grand Coulee, 118% of normal at Columbia above The Dalles, and 93% of normal at the Snake River above Ice Harbor. Daily precipitation records included Spokane with 2.26 cm (0.89”), Lewiston with 1.70 cm (0.67”), Pocatello with 1.85 cm (0.73"), and Meacham with 1.88 cm (0.74”). It is common during the warmer time of year, that temperatures remain cooler than normal where precipitation falls the most frequently. Consequently, there were big temperature swings, as evidenced by the mean temperature departures: -15.6 to +3.4 °C (-28.1 °F to +6.2 °F). The warmest readings, relative to normal, were west of the Cascades (again, typical of this type of weather pattern). Overall, the month averaged +0.4 °C (+0.8 °F) from normal. Some of the daily record high temperatures included Medford, with 40.6 °C (105 °F), Portland with 38.9 °C (102 °F), Seattle with 32.2 °C (90 °F), and Salem with 37.8 °C (100 °F). As the month ended and July began, the high pressure area that covered the region really strengthened and expanded west to east, thereby effectively cutting off the moist southerly flow of the past couple of months.

July 2006, was very warm and dry and contained a mid to late month heat wave that briefly spanned most of the U.S. and southern Canada. July precipitation was 58% of normal at Columbia above Grand Coulee, 55% of normal at Columbia above The Dalles, and 50% of normal at the Snake River above Ice Harbor. Spotty, daily precipitation records were set at Mullan Pass, with 2.77 cm (1.09”), and Quillayute, with 0.58 cm (0.23”). The regional temperatures departed an impressive +2.6 °C (+4.6 °F), with some daily high temperature records at Pendleton, with 36.7 °C (98 °F), Seattle at 27.8 °C (82 °F), Medford at 41.1 °C (106 °F), Roseburg at 37.8 °C (100 °F), Pasco at 44.4 °C (112 °F), and Missoula at 37.8 °C (100 °F). Cooler temperatures arrived for August, as part of the high pressure area moved off to the west, and another part off to the east.

As a result, most of the region saw a north to northwesterly flow bringing Pacific air inland, rather than the continental flow regime of the previous months. The Pacific flow meant more marine air for western interior valleys, and mainly cooler daytime high temperatures east of the Cascades. This was not an exceptionally wetter pattern though, except toward the end of the month when weather disturbances clipped the Canadian tier, producing some precipitation as far south as Washington and northern Idaho. Preliminary precipitation records, through 28 July, showed Columbia above Grand Coulee having received 45% of the monthly normal, Columbia above The Dalles, 38%, and the Snake River above Ice Harbor, 41% of normal. Regional temperatures, based on combined averages of Seattle, Portland and Spokane, departed +0.3 °C (+0.5 °F) from normal. As we have now trended into September, we find the high pressure area stronger, again, across mainly B.C. and the northern U.S. districts. We are back into a drier and warmer mode for the first half of September.

September finished generally warmer and drier than normal, region-wide. High pressure with offshore flow caused record high temperatures west of the Cascades while eastern districts initially flirted with record low temperatures, but then warmed up nicely toward the end of the month. Precipitation ended up 77% of normal at Columbia above Grand Coulee, 99% of normal at the Snake River above Ice Harbor, and 80% of normal at Columbia above The Dalles for the month of September. The seasonal precipitation for the Columbia Basin for the water year from October 2005 through September 2006 is shown in Chart 2. Chart 3 shows the rate of precipitation accumulation during the year at Columbia above Grand Coulee, Snake River above Ice Harbor, and Columbia Basin above The Dalles. Regional temperatures departed +0.3 °C (+0.5 °F), and this included several record high temperatures and a few record low readings. The record highs were Seattle at 26.1C (79 °F), Wenatchee at 35.6 °C (96 °F), Moses Lake at 36.7 °C (98 °F), and Redmond at 32.8 °C (91 °F). Pocatello at -1.6 °C (29 °F), Missoula with 0.6 °C (33 °F), Omak at 3.3 °C (38 °F), Meacham with -2.2 °C (28 °F), and Butte with -3.3 °C (26 °F) were record low temperatures. Chart 4 shows monthly temperature departures for the basin each month from October 2005 through September 2006.

Streamflow

The observed inflow and outflow hydrographs for the Canadian reservoirs for the period 1 July 2005 through 31 July 2006 are shown on Charts 5-7. Libby hydrographs are shown in Chart 8. Observed flow, as well as computed unregulated flow hydrographs for the same 13-month period for Kootenay Lake, Columbia River at Birchbank, Grand Coulee, and The Dalles are shown on Charts 9-12, respectively. Observed and unregulated flow hydrographs at The Dalles during the April-July 2006 period, including a plot of flows occurring if regulated only by the four Treaty reservoirs, is provided in Chart 13. Composite operating year unregulated streamflows in the basin above The Dalles were above normal and approximately 11% above last year’s below average streamflows.

Unregulated inflows during spring runoff were highest in May 2006 at 128% of average at The Dalles. The August 2005 through July 2006 runoff for The Dalles was 173.9 km^3 (141.0 Maf), 102% of the 1971-2000 average. The peak-unregulated discharge for the Columbia River at The Dalles was 19, 7348 m^3/s (696,920 cfs) and occurred on 25 May 2006. The 2005-2006 average monthly unregulated streamflows and their percentage of the 1971-2000 average monthly flows are shown in the following tables (metric and English) for the Columbia River at Grand Coulee and The Dalles. These flows have been adjusted to exclude the effects of regulation provided by storage reservoirs.

Columbia River Stream Flow

Time	Columbia River at Grand Coulee			Columbia River at The Dalles		
Period	Natural Flow		Percent of	Natural Flow		Percent of
Period	Cfs	m^3/s	Average	Cfs	m^3/s	Average
Aug.2005	74,836	2119	71	95,370	2701	70
Sep.2005	49,678	1407	80	71,904	2036	77
Oct.2005	71,909	2036	160	100,263	2,839	121
Nov.2005	50,030	1417	102	83,446	2,363	88
Dec.2005	38,044	1077	88	82,136	2,326	83
Jan.2006	67,146	1901	160	145,315	4,115	142
Feb.2006	45,000	1274	95	104,112	2,948	86
Mar.2006	54,415	1541	82	139,260	3,943	84
Apr.2006	142,356	4031	120	298,466	8,452	130
May.2006	344,047	9742	125	574,022	16,255	128
Jun.2006	308,789	8744	103	450,576	12,759	99
Jul.2006	149,503	4233	75	196,510	5565	74
Period Average	116,664	3304	103	195,523	5537	102

Seasonal Runoff Forecasts and Volumes

April-August 2006 runoff volumes, adjusted to exclude the effects of regulation of upstream storage, are listed below for eight locations in the Columbia Basin:

Location	**Volume in km^3**	**Volume in KAF**	**Percentage of 1971-2000 Average**
Libby Reservoir Inflow	8.15	6,629	106
Duncan Reservoir Inflow	2.61	2,120	104
Mica Reservoir Inflow	13.39	10,896	96
Arrow Reservoir Inflow	26.27	21,366	93
Columbia River at Birchbank	49.85	40,550	100
Grand Coulee Reservoir Inflow	75.22	61,189	101
Snake River at Lower Granite	31.42	25,557	112
Columbia River at The Dalles	119.91	97,541	108

Forecasts of seasonal runoff volume, based on precipitation and snowpack data, were prepared in 2006 for a large number of locations in the Columbia River Basin and updated each month as the season advanced. Table 1 lists the April through August inflow volume forecasts for Mica, Arrow, Duncan, and Libby projects as well as The Dalles. The actual runoff volume for these five locations is also given in Table 1. The forecasts for Mica, Arrow, and Duncan inflow were prepared by B.C. Hydro. The forecasts for the lower Columbia River inflows were prepared by the National Weather Service River Forecast Center, in cooperation with the U.S. Army Corps of Engineers, National Resource Conservation Service, Bureau of Reclamation, and B.C. Hydro. The Libby inflow forecast is prepared by the U.S. Army Corps of Engineers. The 1 April 2006 forecast of January through July runoff for the Columbia River above The Dalles was132 km^3 (107.0 Maf) and the actual observed runoff was 141 km^3 (114.7 Maf).

The following tabulations summarize the monthly forecasts since 1970 of the January-July runoff for the Columbia River above The Dalles compared with the actual runoff volume in km^3 and Maf. The average January-July runoff volume for the 1971-2000 period is 132.4 km^3 (107.3 Maf).

January-July Volume Runoff Forecasts at The Dalles in km^3 & Maf

Year	Jan	Feb	Mar	Apr	May	Jun	Actual
1970	101.8/82.5	122.7/99.5	115.2/93.4	116.3/94.3	117.3/95.1	---	118/95.7
1971	136.8/110.9	159.7/129.5	155.4/126	165.3/134	164.1/133	166.5/135	169.6/137.5
1972	135.8/110.1	157.9/128	171.1/138.7	180.2/146.1	180.1/146	180.1/146	187.1/151.7
1973	114.8/93.1	111.6/90.5	104.5/84.7	102.4/83	99.2/80.4	97.1/78.7	87.8/71.2
1974	151.7/123	172.7/140	180.1/146	183.8/149	181.3/147	181.3/147	192.8/156.3
1975	118.5/96.1	131/106.2	141.5/114.7	143.9/116.7	142.1/115.2	139.4/113	138.6/112.4
1976	139.4/113	143.1/116	149.3/121	153/124	153/124	153/124	151.5/122.8
1977	93.4/75.7	76.7/62.2	69/55.9	71.7/58.1	66.4/53.8	70.8/57.4	66.4/53.8
1978	148/120	140.6/114	133.2/108	124.6/101	128.3/104	129.5/105	130.3/105.6
1979	108.5/88	97/78.6	114.7/93	107.7/87.3	110.6/89.7	110.6/89.7	102.5/83.1
1980	109.7/88.9	109.7/88.9	109.7/88.9	110.6/89.7	111.8/90.6	120.5/97.7	118.2/95.8
1981	130.7/106	104.2/84.5	104.2/84.5	101/81.9	102.6/83.2	118.3/95.9	127.5/103.4
1982	135.7/110	148/120	155.4/126	160.4/130	161.6/131	157.9/128	160.2/129.9
1983	135.7/110	133.2/108	139.4/113	149.3/121	149.3/121	146.8/119	146.4/118.7
1984	139.4/113	127/103	120.4/97.6	125.8/102	132/107	140.6/114	146.9/119.1
1985	161.6/131	134.4/109	129.5/105	121.6/98.6	121.6/98.6	123.3/100	108.2/87.7
1986	119.4/96.8	115.1/93.3	127/103	130.7/106	133.2/108	133.2/108	133.6/108.3
1987	109.7/88.9	101/81.9	96.2/78	98.7/80	94.6/76.7	93.5/75.8	94.4/76.5
1988	97.7/79.2	92.3/74.8	89.7/72.7	91.3/74	93.9/76.1	92.5/75	90.9/73.7
1989	124.6/101	125.8/102	116.2/94.2	122.7/99.5	121.6/98.6	119.5/96.9	111.8/90.6
1990	106.7/86.5	124.6/101	128.3/104	118.4/96	118.4/96	122.7/99.5	123/99.7
1991	143.1/116	135.7/110	132/107	130.7/106	130.7/106	128.3/104	132.1/107.1
1992	114.2/92.6	109.9/89.1	103/83.5	87.8/71.2	87.8/71.2	83.6/67.8	86.8/70.4
1993	114.2/92.6	106.7/86.5	95.3/77.3	94.5/76.6	88.7/71.9	106.2/86.1	108.5/88
1994	98.3/79.7	94.1/76.3	96.3/78.1	90.3/73.2	93.1/75.5	94.2/76.4	92.5/75
1995	124.7/101.1	122.9/99.6	116.3/94.3	122.9/99.6	122.9/99.6	120.8/97.9	128.3/104
1996	143.1/116	150.5/122	160.4/130	155.4/126	165.3/134	173.9/141	171.8/139.3
1997	170.2/138	178.9/145	175.2/142	183.8/149	188.7/153	196.1/159	196.1/159
1998	106.6/86.4	117.4/95.2	113.1/91.7	112/90.8	109.9/89.1	124.6/101	128.3/104
1999	143.1/116	148/120	160.4/130	157.9/128	153/124	151.7/123	153.1/124.1
2000	129.5/105	130.7/106	129.5/105	129.5/105	129.5/105	125.8/102	120.9/98
2001	99.2/80.4	81.9/66.4	72.3/58.6	69.2/56.1	69.7/56.5	68.5/55.5	71.8/58.2
2002	123.3/100	125.8/102	120/97.3	118.9/96.4	121.1/98.2	123.3/100	128/103.8
2003	99.3/80.5	93.3/75.6	92.4/74.9	105.2/85.3	111.3/90.2	110.1/89.3	108.2/87.7
2004	127/103	123.3/100	114.6/92.9	103.9/84.2	98.1/79.5	105/85.1	102.4/83
2005	105.6/85.6	101.6/82.4	87.2/70.7	91/73.8	92.1/74.7	98.4/79.8	100.3/81.3
2006	124.6/101	136.9/111	132/107	132/107	135.7/110	136.9/111	141.5/114.7

V - RESERVOIR OPERATION

General

The 2005 – 2006 operating year began with Canadian storage at 98.4% full. Libby reservoir (Lake Koocanusa) was near full elevation 748.9 m (2457 feet) oat the start pf the operating year and releasing water to meet objectives for flow augmentation for listed salmon species in the U.S.

The 2005 – 2006 operating year was one of near average water supply across the basin, but the shape of the runoff was very concentrated into the last half of May and June. Because of the unusual shape of runoff, there was some localized flooding in the Kootenai River at Bonners Ferry and a Summer Storage Agreement was signed to storage some of the freshet in May and June of 2006 for release in August and September 2006.

The CRTOC signed one operating agreement to enhance fishery operating at Arrow early in the year. Libby Dam operated to meet the needs of the U.S. Fish and Wildlife Service 2006 BiOp for sturgeon and the NOAA Fisheries BiOp. A new Libby Operating Plan was prepared on 21 April 2006 to reflect the 18 February 2006 Biological Opinion. At the end of the 2005 – 2006 operating year Canadian storage was nearly full at 97.1% full on 31 July 2006.

Canadian Treaty Storage Operation

At the beginning of the 2005-2006 operating year on 31 July 2005, actual Canadian Treaty storage (Canadian storage) was at 18.8 km^3 (15.2 Maf) or 98.4% full. It drafted to a minimum of 3.9 km^3 (3.2 Maf) on 9 April 2006. Like the previous year, Canadian storage refilled to near full by the end of the operating year, reaching 18.6 km^3 (15.0 Maf) or 97.1% full on 31 July 2006.

As specified in the Detailed Operating Plan (DOP), the release of Canadian storage is made effective at the Canadian-U.S. border. Accordingly, releases from individual Canadian projects can vary from the release required by the DOP Treaty Storage Regulation (TSR) plus supplemental operating agreements so long as this variance does not impact the ability of the Canadian system to deliver the sum of CRT outflows from Arrow and Duncan reservoirs. Variances from the DOP storage operation are accumulated in respective Flex accounts. An overrun in an account occurs when actual project releases are greater (contents are lower) than those specified by the DOP. Conversely, an underrun occurs when actual project releases are less (contents are higher) than those specified by the DOP. Flex accounts for Mica, Revelstoke, Arrow, and Duncan are balanced at any point in time to ensure that under/overruns do not impact the total CRT release required at the Canadian-U.S. border. The terms under/overrun are used in the description of Mica Reservoir operations below.

Mica Reservoir

As shown in Chart 5, Mica (Kinbasket) reservoir was at elevation 750.40 m (2461.9 feet) on 31 July 2005. The reservoir continued to refill to reach a maximum elevation of 750.56 m (2462.5 feet) on 8 August 2005, 3.82 m (12.5 feet) below full pool. Since reaching its peak level, the reservoir continued to draft and departed from normal levels beginning in late summer due to low basin inflow conditions in August and September. As inflows continued to recede throughout the fall and winter period and outflows increased to meet winter load requirements, the reservoir drafted steadily, reaching 735.27 m (2412.3 feet) on 31 December 2005. The reservoir continued to draft January through late April 2006, reaching a minimum elevation of 727.00 m (2385.2 feet) on 7 April 2006, near normal elevation for this date. Mica outflows from April through June 2006 were generally lower than normal. This reduction in outflows was made to maximize generation at the Peace River powerplants in order to minimize the risk of spill at Williston Reservoir (Peace River). This condition combined with above normal inflows in May and June resulted in continued filling of the reservoir to above normal levels, ending August 2006, at 751.73 m (2466.3 feet) or 2.03 m (6.6 feet) above the mean elevation for this date.

Inflow into Mica reservoir was 89 percent of normal over the period August 2005 to December 2005. Over this same period, Mica outflow varied from a monthly average low of about 660 m^3/s (23,300 cfs) in October to a monthly average high of about 1,034 m^3/s (36,500 cfs) in September. Inflow into Mica reservoir was 106 percent of normal over the period January 2006 to July 2006. Outflow over this same period varied from a monthly average high of 598 m^3/s (21,100 cfs) in March to a monthly average low of 71 m^3/s (2,500 cfs) in June. The Mica project had an underrun of 3,643.8 cubic hectometers (hm^3) (1,489.4 thousand second-foot-days (ksfd)) on 31 July 2005 which was also the maximum underrun for the year. The underrun was gradually reduced to a minimum of -11.0 hm^3 (-4.5 ksfd) on 7 July 2006 before increasing to 277.2 hm^3 (113.3 ksfd) on 31 July 2006.

The B.C. Hydro Non-Treaty Storage Agreement (NTSA) active storage account was at 912.5 hm^3 (373.0 ksfd) on 31 July 2005 and 2,159.0 hm^3 (882.5 ksfd) on 31 July 2006. The corresponding U.S. NTSA account was at 234.1 hm^3 (95.7 ksfd) and 1261.8 hm^3 (515.8 ksfd), respectively. The NTSA Agreement terminated, with respect to release rights, on 30 June 2004. Under the NTSA Extended Provisions, active storage accounts must be refilled prior to 30 June 2011.

Revelstoke Reservoir

During the 2005-2006 operating year, the Revelstoke project was operated as a run-of-river plant with the reservoir level maintained generally within 0.91 m (3.0 feet) of its normal full pool elevation of 573.02 m (1,880.0 feet). During the spring freshet, March through July, the reservoir operated as low as elevation 571.65 m (1,875.5 feet), or 1.37 m (4.5 feet) below full pool, to provide additional operational space to control high local inflows. Changes in Revelstoke storage levels did not affect CRT storage operations.

Arrow Reservoir

As shown in Chart 6, the Arrow reservoir was at elevation 432.67 m (1419.5 feet) on 31 July 2005, 7.46 m (24.5 feet) below full pool. Influenced by a low initial level, Arrow reservoir drafted to a below normal level, reaching 427.83 m (1403.7 feet) by 31 December 2005, 4.46 m (14.6 feet) below the mean elevation for this date. The reservoir reached its minimum level of the year at elevation 425.88m (1397.3 feet) on 31 March, 2006. The reservoir refilled from April through July, reaching a maximum level of 439.82 m (1443.0 feet) on 10 July 2006, 0.31 m (1.0 feet) below full pool.

Local inflow into Arrow reservoir was 95 percent of normal over the period August to December 2005. Arrow outflow varied from a monthly average low of about 866 m^3/s (30,600 cfs) in November to a monthly average high of 1668 m^3/s (58,900 cfs) in August. Daily outflows in December reached a peak of 2002 m^3/s (70,700 cfs) on 15 December before ramping down to about 1019 m^3/s (36,000 cfs) by the end of the month, in preparation for the start of whitefish spawning. Local inflow into Arrow reservoir was 105 percent of normal over the period January to July 2006. Outflow over this same period varied from a monthly average high of 1473 m^3/s (52,000 cfs) in June to a monthly average low of 569 m^3/s (20,100 cfs) in April. During the same period, a number of ramping tests were conducted when flows were dropped at various rates for a couple of hours per day to assess potential impact on fish.

B.C. Hydro has committed to Department of Fisheries and Oceans (DFO) under the 22 September 2004 letter, to make efforts to continuing the historical winter flow reductions for whitefish protection. In this letter, developed as part of the Columbia Water Use Plan (WUP) process, B.C. Hydro promised to make efforts to protect whitefish over the 5-year period (2005-09) as follows: Tier 1 (0 to 20 percent egg mortality) in 3 out of 5 years, Tier 2 (20 to 40% egg mortality) in 2 out of 5 years, and 0 years with egg mortality greater than 40 percent. In order to achieve both U.S. and Canada nonpower needs, Arrow Reservoir operation was modified during the operating year under the NonPower Uses Agreement and the 2006 Summer Storage Agreement (not Treaty). The NonPower Uses agreement helped to enhance the success of whitefish and rainbow trout spawning and emergence downstream of the Arrow project in British Columbia and to provide additional non-power benefits in the U.S.

From 1 January 2006 to 19 January 2006, Arrow outflow was held on average 750 m^3/s (26,500 cfs) to maintain low river levels during the whitefish peak spawning period. This operation reduced the number of eggs being dewatered during the incubation period in February and March 2006. Arrow outflow, from February through March 2006, was held above 566 m3/s (20,000 cfs) to help protect deposited eggs. These flow changes resulted in a Tier 2 protection for whitefish for the 2005/2006 operating year. During April and May 2006, Arrow outflows were maintained at or above 425 m3/s (15,000 cfs) to ensure successful rainbow trout spawning below Arrow, at water levels that could be maintained until hatch.

The 2006 Summer Storage Agreement (not Treaty) was signed on 8 June 2006 between the Bonneville Power Administration (BPA) and the British Columbia Hydro and Power Authority (B.C. Hydro). This agreement helped to reduce inflow into Grand Coulee during the freshet, provide summer flow support for U.S. fisheries, and enhance Arrow reservoir elevations for summer recreation. The agreement did not infringe on Treaty or 1990 Non-Treaty Storage Agreement (1990) storage operations.

Duncan Reservoir

Operation of the Duncan reservoir during the 2005- 06 operating year attempted to implement most of the operational constraints agreed upon in the recently completed Water Use Plan (WUP). As shown in Chart 7, the Duncan reservoir refilled to a maximum elevation of 576.48 m, (1891.4 feet) on 31 July 2005, 0.17 m (0.6 feet) below full pool. The reservoir was maintained within about 0.3 m (1.0 feet) below full pool through August as a flood buffer and to support recreation on the reservoir, as stipulated in the Duncan WUP.

The project passed inflows until 1 September 2005 when the reservoir started to draft. Discharges were increased to about 198 m^3/s (7,000 cfs) across September to facilitate drafting of the reservoir prior to the start of the kokannee and whitefish spawning downstream of Duncan Dam. There were a number of ramping tests conducted during the month when flows were dropped at various rates from 7 to 5 kcfs for several hours per day to assess potential impact on fish. For the first 3 weeks of October discharges were reduced to maintain a 73 m^3/s (2,600cfs) flow at the DRL (Duncan River below the Lardeau confluence) gauging station to facilitate spawning at lower flows to limit the risk of over-winter dewatering of redds. Discharges were increased in the last week of October to bring DRL to a maximum flow of 110 m^3/s (3,900cfs) and maintained until 21 December 2005, when Duncan discharges were gradually increased to 283 m^3/s (10,000 cfs) by year end.

For the first two weeks of January 2006, Duncan discharge was kept near 283 m^3/s (10,000 cfs) since the reservoir level was quite high at the beginning of the year, and to help reduce Arrow flows in aid of whitefish spawning. Given a low forecast for the 2006 freshet, B.C. Hydro requested a variance to the Duncan Flood Control Curve for 28 February 2006 from 551.0 m (1807.7 ft) to 552.4 m (1812.5 ft), which was subsequently approved. The additional storage on 28 February increases the ability to maintain a minimum river flow at DRL of 73 m^3/s (2,600 cfs) for incubation of fish eggs during the March-April period as agreed to under the Duncan Water Use Plan. Flows were reduced and held near 198 m^3/s (8,000 cfs) for the balance of January and then gradually dropped to 142 m^3/s (5,000 cfs) across February in order to target a flood control level of 552.4 m (1812.5 ft) on 28 February 2006. Discharges in March through the early May 2006 were adjusted as required to provide a minimum flow of 73 m^3/s (2,600 cfs) at the DRL and to empty the reservoir prior to the freshet. The reservoir drafted to a minimum elevation of 546.95 m (1794.5 feet) on 17 April 2006, 0.08 m (0.3 feet) above empty.

The observed seasonal water supply at Duncan for the February through September period was 101 percent of normal. Reservoir discharge was reduced to the minimum of 3 m^3/s (100 cfs) on 4 May 2006 to initiate refill. Duncan reservoir continued to pass the minimum flows until end of June 2006 when discharges were gradually increased to control the rate of refill. When the reservoir reached 1891 feet in July, Duncan reservoir was operated to pass inflows from mid July through August. The reservoir refilled to full pool at about 576.7 m (1892 feet) on 23 August 2006.

Libby Reservoir

As shown in Chart 8, Lake Koocanusa began July 2005 near elevation 748.9 m (2457 feet). Inflow ranged from 821 m^3/s (29 kcfs) near the beginning of the month, to a low of 283 m^3/s (10 kcfs) at the end of the month. Outflow for the month averaged 611 m^3/s (21.6 kcfs). Until about mid –month, flow was kept between 538 m^3/s (19 kcfs) and full powerhouse, 679 m^3/s (24 kcfs), in order to control rate of fill and to provide space for late season rain events and snowmelt. Libby reached a peak elevation of 749.3 m (2458.4 feet) on 10 July. The state of Montana submitted draft and final System Operational Requests (SOR 2005-MT-1) to the Technical Management Team (TMT) on 29 June and 6 July to discuss implementation of the Northwest Planning and Conservation Council (NWPCC)

Mainstem Amendments. The request was to draft to 743.4 m (2439 feet), 6.1 m (20 feet) from full, by the end of September rather than the end of August as specified in the NOAA Fisheries Biological Opinion (BiOp). On 28 June, U.S. Fish and Wildlife Service (FWS) and the Columbia River Inter-Tribal Fish Commission (CRITFC) submitted SOR-2005-16 requesting the BiOp-specified draft to 743.4 m (2439 feet). The final decision was to draft to elevation 743.4 m (2439 feet) by the end of August. During the month of August, the operational goal was to gradually ramp down flows while meeting the agreed elevation target. Outflow was near 538 m^3/s (19 kcfs) at the end of the July, and was gradually reduced to 340 m^3/s (12 kcfs) near the end of August. The project ended the month at elevation 743.6 m (2439.5 feet).

In September, the project maintained a slow stair step reduction from 340 m^3/s (12 kcfs) to 198 m^3/s (7 kcfs) per TMT agreement to maintain biological productivity. Gradual ramp downs are the preferred operation for biological river health. On 5, 12, and 26 September, outflows were reduced to 283 m^3/s (10 kcfs), 226 m^3/s (8 kcfs) and 198 m^3/s (7 kcfs), respectively. Outflow remained at 198 m^3/s (7 kcfs) for the remainder of the month. The project reached 742 m (2436.4 feet) on 30 September. In October outflows were reduced to most efficient loading with one unit (133 m^3/s or 4.7 kcfs). Heavy precipitation caused the project to fill to 745.5 m (2445.9 feet) by the end of the month. On 31 October, outflow was increased to most efficient loading with two units (266 m^3/s or 9.4 kcfs).

Outflow remained at 266 m^3/s (9.4 kcfs) until the middle of November when it was increased to 558 m^3/s (19.7 kcfs). Flow was again increased near the end of the month to 577 m^3/s (20.4 kcfs) during the weekdays and decreased over the weekend to around 453 m^3/s (16 kcfs). The project ended the month of November at elevation 742.2 m (2434.9 ft). The December final water supply forecast (WSF) at Libby was 8.15 km^3 (6.625 MAF), or 106 % of the 30 year average, which required an end of December elevation of 734.9 m (2411 ft). In order to draft Libby down to elevation 734.9 m (2411 ft), outflow from Libby was ramped up to full load, near 708 m^3/s (25 kcfs), over several days beginning on 5 December. The outflows followed a weekly load shape with higher flows on weekdays and lower flows on weekends. Starting on 14 December, flows started to ramp down to a target of 283 m^3/s (10 kcfs) on 18 December. This flow was requested by Idaho Fish and Game in order to dive and retrieve lost burbot fishing nets. The nets turned out to be buried and were not able to be recovered. Flows were then ramped up to 566 m^3/s (20 kcfs) by 20 December. On 23 December, flow was reduced to near 453 m^3/s (16 kcfs) and held there through 28 December. At that time, flow began to ramp down following BiOp ramp rates in order to reduce to minimum, 113 m^3/s (4 kcfs), on 8 January. The project ended the month at elevation 735.2 m (2412.2 feet).

Lake Koocanusa began January near elevation 2412 feet. The January final WSF dropped to 6.75 km^3 (5.487 MAF), or 88% of normal, with an end of January VARQ flood control elevation of 739.7 m (2426.7 ft). Outflow continued to be ramped down from 283 m^3/s (10kcfs) on 1 January, to the normal project minimum of 113 m^3/s (4 kcfs) by 8 January, following established project ramp rates. The project was held at minimum flow during the rest of the month, overall passing inflow, and ending the month of January at elevation 735.3 m (2412.3 ft), more than 4.3 m (14 ft) below the end of month flood control elevation. The February final water supply forecast rose to 7.61 km^3 (6.186 MAF), or 99% of normal, requiring a VARQ end-of-month flood control elevation of 735.2 m (2412.0 ft).

The project remained at minimum during February, essentially passing inflow, and ended February at elevation 734.9 m (2411.1 ft).

The March final WSF rose slightly to 7.81 km^3 (6.350 MAF), or 101.6% of normal. That volume required an end of month flood control elevation of 732.8 m (2404.1 ft). Outflow at the beginning of the month started at minimum, or 113 m^3/s (4.0 kcfs). Outflow was increased to 260.4 m^3/s (9.2 kcfs) on 8 March, in order to reach the end of month flood control target elevation. Outflow was reduced to approximately 203.8 m^3/s (7.2 kcfs) on weekends and raised back up to 260.4 m^3/s (9.2 kcfs) during the weekdays. On 30 March, outflow began to ramp back down to minimum. The project ended March at elevation 732.8 m (2404.3 ft). During April, the project operated at minimum flow of 113 m^3/s (4.0 kcfs) over the entire month. The April final WSF was 7.47 km^3 (6.076 MAF) or 97.2% of average. This required a maximum end of April elevation of 736.7 m (2417.0 ft). The project filled over the entire month and ended at elevation 735.5 m (2413.2 ft), almost 1.2 m (4 ft) below the end of month target.

In May, operations normally shift from strict flood control elevation targets to a balancing act of project refill and flood control. In early May, the Corps and USFWS agreed to a stacked flow sturgeon pulse operation. The goal of this operation was to match increased Libby discharges with the rise in local inflow at Bonners Ferry. The objective was to achieve both depth and temperature conditions believed to be beneficial to the spawning of white sturgeon in the area. Starting around 8 May, short term modeling started to indicate a rise in local inflow due to snow melt beginning to occur around the 18 May. Operating for flood control and the stacked flow operation, the project was increased from minimum flow to full powerhouse capacity of about 708 m^3/s (25 kcfs) beginning on 15 May, reaching full powerhouse capacity on 18 May.

An unusually sharp warm weather event began to dominate the entire basin area in mid-May. The magnitude of inflow rises were not reflected in available long-term model forecasts. Project inflows rose sharply from 510 m^3/s (18 kcfs) on 11 May, to a peak day average of 2,180 m^3/s (77 kcfs) on 21 May, and then receded to 863 m^3/s (30.5 kcfs) by 31 May. Outflow was generally held at full powerhouse capacity from 18 May, through the end of the month. However, some decreases were made in order to keep the stage at Bonners Ferry under flood stage. Libby Dam filled to elevation 746.5 m (2449.1 ft) by midnight on 31 May. Slightly warmer early June temperatures and some thunderstorm activity brought inflows back up to nearly 1,359 m^3/s (48 kcfs) by 4 June. Inflows then receded slightly but began rising again on 7 June. Libby continued to release full powerhouse outflows of about 693 m^3/s (24.5 kcfs) until 8 June, at which time spill was added and total outflow was increased to 1,076 m^3/s (38 kcfs).

The decision to initiate spill was based on various scenario modeling analyses. Results showed that RCC needed to be proactive and increase outflows to avoid a fill and uncontrolled-spill scenario. By 14 June, inflows had receded to 982 m^3/s (34.7 kcfs) for a day average. Unusually strong rainstorm activity began on 15 June, and inflows rose to as high as a calculated six-hour average of 1,874 m^3/s (66.2 kcfs) on 17 June. Project outflows were increased from 1,076 m^3/s (38 kcfs) to 1,415 m^3/s (50 kcfs) on 16 June, and then up to 1,557 m^3/s (55 kcfs) which included 877 m^3/s (31 kcfs) spill on 17 June. During the time of peak inflows, the project outflow was 1,472 m^3/s (52 kcfs), thus reducing uncontrolled outflow downstream by 396 m^3/s (14 kcfs). The flow operation controlled Libby pool to full pool elevation. By 19 June, calculated six-hour inflows had dropped to 1,189 m^3/s (42 kcfs) and the project was holding 1,557 m^3/s (55 kcfs) in order to provide some storage for any unexpected inflow rises. In combination with river rises below the project and required releases from Libby Dam, Bonner Ferry stage reached the flood level of 537.7 m (1764.0 ft) late on 16 June, and appeared to have peaked late on 18 June, at 538.47 m (1766.63 ft), with only minimal direct flood damages noted. Bonners Ferry stage went below flood stage the afternoon of 22 June. Beginning 20 June, spill was decreased 28.3 m^3/s (1 kcfs) every four hours and reached 170 m^3/s (6 kcfs) on 24 June (total outflow was 849 m^3/s or 30 kcfs). Spill was reduced to zero on 27 June. The project ended the month at elevation 748.8 m (2456.73 ft).

Lake Koocanusa began the month of July at elevation 748.9 m (2456.9 ft). Across the month, inflow continually decreased from nearly 651 m^3/s (23 kcfs) at the beginning of July to near 255 m^3/s (9 kcfs) by the end of the month. Outflow was decreased from 538 m^3/s (19 kcfs) on 1 July, to a target outflow of 481 m^3/s (17 kcfs) on 8 July. This discharge was the calculated flat flow that would provide a 6.1 m (20 ft) draft by the end of August. During July, the Montana proposal was discussed within TMT. The proposal supported a 3.05 m (10 ft) to 746.5 m (2449 ft) by the end of September. After many discussions, it was agreed that outflow would be reduced to 3 units at maximum discharge, 410 m^3/s (14.5 kcfs), through the remainder of July and August. Following this agreement, outflow was reduced to that level on 25 July. Inflow averaged 396 m^3/s (14.0 kcfs) through July, while outflow averaged 476 m^3/s (16.8 kcfs). The project ended July at elevation 747.8 m (2453.3 ft).

During August, the project continued to discharge nearly 396 m^3/s (14 kcfs) or 3 units at maximum discharge. Inflow continued to decrease across the month averaging 187 m^3/s (6.6 kcfs). Outflow averaged 399 m^3/s (14.1 kcfs). Lake Koocanusa ended the month at elevation 744.7 m (2443.3 ft). Starting on 1 September, outflow was reduced to 255 m^3/s (9 kcfs) following the BIOP ramping rates. Outflow from Libby is expected to remain at this level through the rest of the month.

Kootenay Lake

As shown in Chart 9, the level of Kootenay Lake at Queens Bay was at elevation 531.83 m (1744.8) on 31 July 2005. As runoff receded across August, Kootenay Lake reservoir began to draft and discharges were adjusted to control reservoir levels slightly below the IJC limits. When the Kootenay Lake level measured at Nelson was drafted below the trigger elevation of 531.36 m (1743.32 ft) on 6 August 2005, discharges were adjusted to keep the lake level at or below the control level until the end of August 2005. By 31 December 2005, Kootenay Lake reached an elevation of 531.81 m (1744.8 ft), 0.17 m (0.5 feet) below the maximum IJC level.

Kootenay Lake was drafted during January to April 2006 to remain below the maximum IJC level and to meet generation requirements. Discharges from the lake were kept to the maximum possible through Grohman Narrows (a hydraulic restriction on lake discharges) until 20 June 2006. On 5 April 2006, Kootenay Lake reached its minimum elevation for the year of 530.1 m (1739.3 ft). The Kootenay Lake Board of Control declared the commencement of the spring rise for the regulation of Kootenay Lake on 9 April 2006, when Brilliant began to spill. Following the declaration of spring freshet, Kootenay Lake was operated in accordance to the IJC lowering formula.

Kootenay Lake discharge was increased in accordance with the IJC order for Kootenay Lake. Inflow peaked at 3558 m^3/s (125,600 cfs) on 19 May 2006. Discharge from the lake peaked at 2294 m^3/s (81,000 cfs) on 22 June 2006. Kootenay Lake reached a peak elevation of 533.86 m (1751.5 ft) on 20 June 2006, the highest level since 1997.

As runoff receded during July, Kootenay Lake reservoir began to draft and discharges were adjusted to control reservoir levels slightly below the IJC limits. When the Kootenay Lake level measured at Nelson was drafted below the trigger elevation of 531.36 m (1743.32 ft) on 2 August 2006, discharges were adjusted to keep the lake level at or below the control level until the end of August.

VI - POWER AND FLOOD CONTROL ACCOMPLISHMENTS

General

During the period covered by this report, Duncan, Arrow, and Mica reservoirs were operated for power, flood control, and other benefits in accordance with the CRT and operating plans and agreements described in Section III. Consistent with all DOP's prepared since the installation of generation at Mica, the 2005-2006 and 2006-2007 DOP's were designed to achieve optimum power generation at-site in Canada and downstream in Canada and the U.S., in accordance with paragraph 7 of Annex A of the CRT.

Power operations for the whole of Canadian Storage are developed through Critical Rule Curves (CRC), Assured Refill Curves (ARC) and Variable Refill Curves (VRC). The VRCs are dependent upon the water supply in any given water year and the VRC is updated each month with the development of a new water supply forecast. The monthly VRC calculation for Mica, Arrow and Duncan are shown in Tables 2 – 4 and 2M – 4M. The calculation for Libby VRCs is shown in Tables 5 and 5M. Libby VRCs are used in preparation of the Treaty Storage Regulation (TSR).

During the period covered by this report, Libby operated for power during October through December 2005 as developed in the TSR in accordance with the CRT and 2003 CRT FCOP. Libby operated to Principal Component Methodology water supply and flood control draft in December 2005. The December forecast was 106% of average, and the recommended draft for Libby reservoir was 2.46 km^3 (2 Maf), to elevation 734.9 m (2411 feet) on 31 December.

Libby operated to VARQ (Variable Flow) flood control in the January through spring period. The USFWS finalized a Biological Opinion on 18 February 2006 for white sturgeon in the Kootenai River downstream of Libby Dam. The Libby Operating Plan (LOP) was updated on 21 April 2006, and the Corps signed a Record of Consultation and Summary of Decision (ROCASOD) on the BiOp on 8 May 2006. Libby reservoir operated to a stacked flow operation for sturgeon beginning 14 May 2006. This was followed by above average precipitation in early and mid-June 2006 and spill from Libby Dam. The reservoir refilled and remained near full through June.

Flood Control

The 2006 water supply forecasts averaged slightly above normal across the Columbia River Basin, and the reservoir system, including the Columbia River Treaty projects were required to draft for flood control in preparation for the spring freshet. Inflow forecasts and reservoir regulation modeling were done weekly throughout the winter and spring. Projects were operated according to the 2003 Flood Control Operating Plan. The unregulated peak flow at The Dalles, Oregon, shown on Chart 13, is estimated at 20,564 m^3/s (724,000 cfs) on 25 May 2006 and a regulated peak flow of 11,357 m^3/s (401,000 cfs) occurred on 29 May 2006 as measured at the United States Geological Survey gage at The Dalles Oregon. The unregulated peak stage at Vancouver, Washington was calculated to be 7.95 m (26.07 ft) on 26 May 2006 and the highest observed stage was 3.97 m (13.0 ft) on 30 May 2006.

Chart 14 shows the relative filling of Arrow and Grand Coulee during the filling period and compares the regulation to guidelines provided in Chart 6 of the Columbia River Treaty Flood Control Operating Plan. Low runoff conditions last year and slightly below normal runoff conditions this year caused Mica to be drafted very deeply for power. There were no daily operations specified for Arrow and the projects were able to meet both fish flow and flood control objectives.

In operating year 2005-2006, the Canadian Entity had selected to operate Mica and Arrow to the flood control storage allocations of 4.4 km^3 (3.6 Maf) maximum draft at Arrow and 5.03 km^3 (4.08 Maf) maximum draft at Mica, as allowed under the 2003 FCOP. The operating committee agreed to this allocation on 13 July 2005.

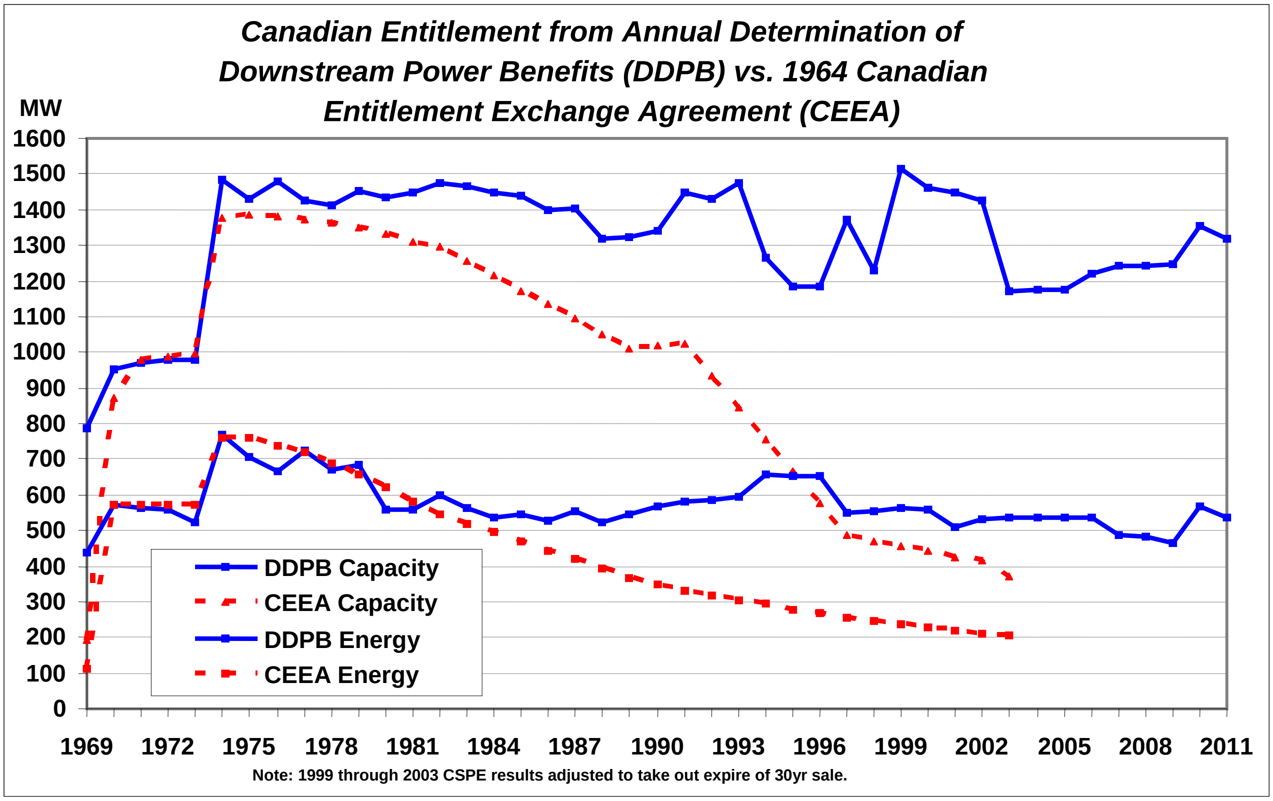
Computations of the Initial Controlled Flow (ICF) for system flood control operation were made in accordance with the Treaty Flood Control Operating Plan. For 2006, the computed ICF at The Dalles was 9,461 m^3/s (334,115cfs) based on the January forecast; 10,354 m^3/s (365,655) based on the February forecast ; 9723 m^3/s (343,367cfs) based on the March forecast; 10,154 m^3/s (358,600cfs) based the April forecast; and 9,919 m^3/s (350,297cfs) based on the May forecast. As mentioned earlier, the observed peak flow at The Dalles was 11,078 m^3/s (391,200 cfs) on 27 May 2006. Table 6 shows data for the May ICF computation.

Canadian Entitlement

From 1 August 2005, through 30 September 2006, the U.S. Entity delivered the Canadian Entitlement to downstream power benefits from the operation of Canadian Treaty storage to the Canadian Entity, at existing points of interconnection on the Canada-U.S. border. The amounts returned, not including transmission losses and scheduling adjustments, are listed in Section III of this report, under the heading Canadian Entitlement.

No Entitlement power was disposed directly in the U.S. during 1 August 2005 through 30 September 2006, as allowed under specific provisions of the 29 March 1999 Agreement on “Disposals of the Canadian Entitlement within the U.S. for 4/1/98 through 9/15/2024.”

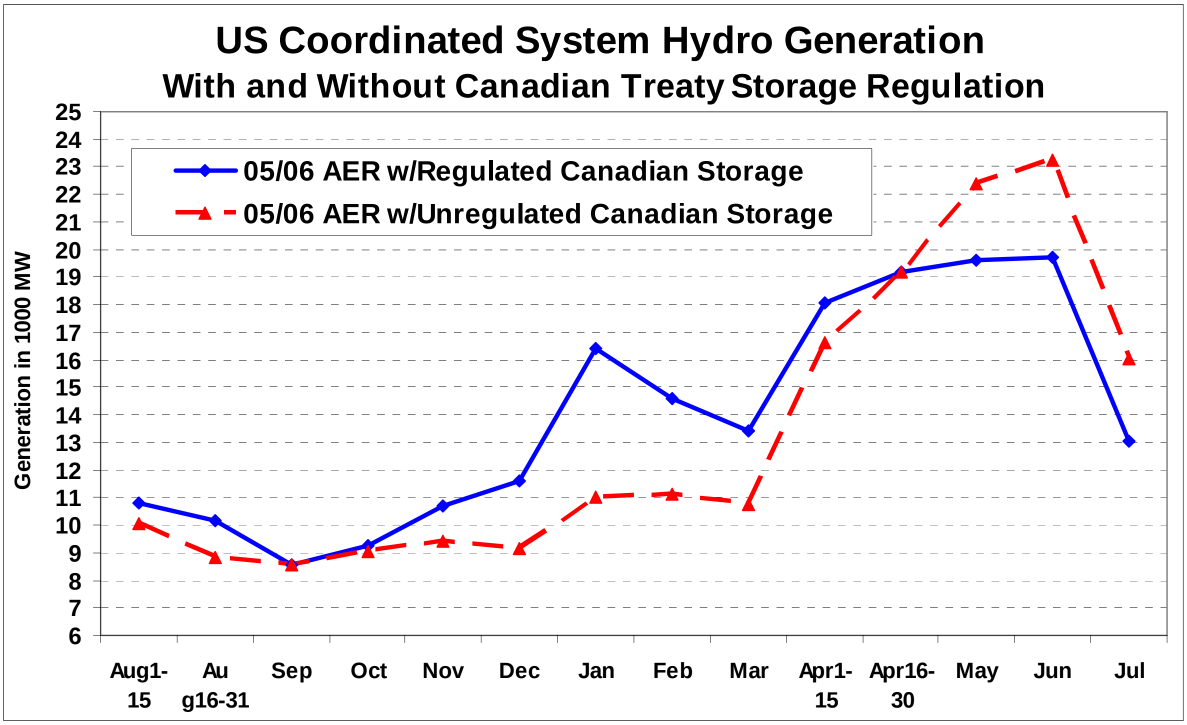
The following graph shows the historic Canadian Entitlement computation from the DDPB studies together with the amount sold under the CEPA.



In accordance with the Canadian Entitlement Allocation Extension Agreement, dated April 1997, the U.S. Entity granted permission for the non-federal downstream U.S. parties to make use of the U.S. one-half share of the CRT downstream power benefits (U.S. Entitlement).

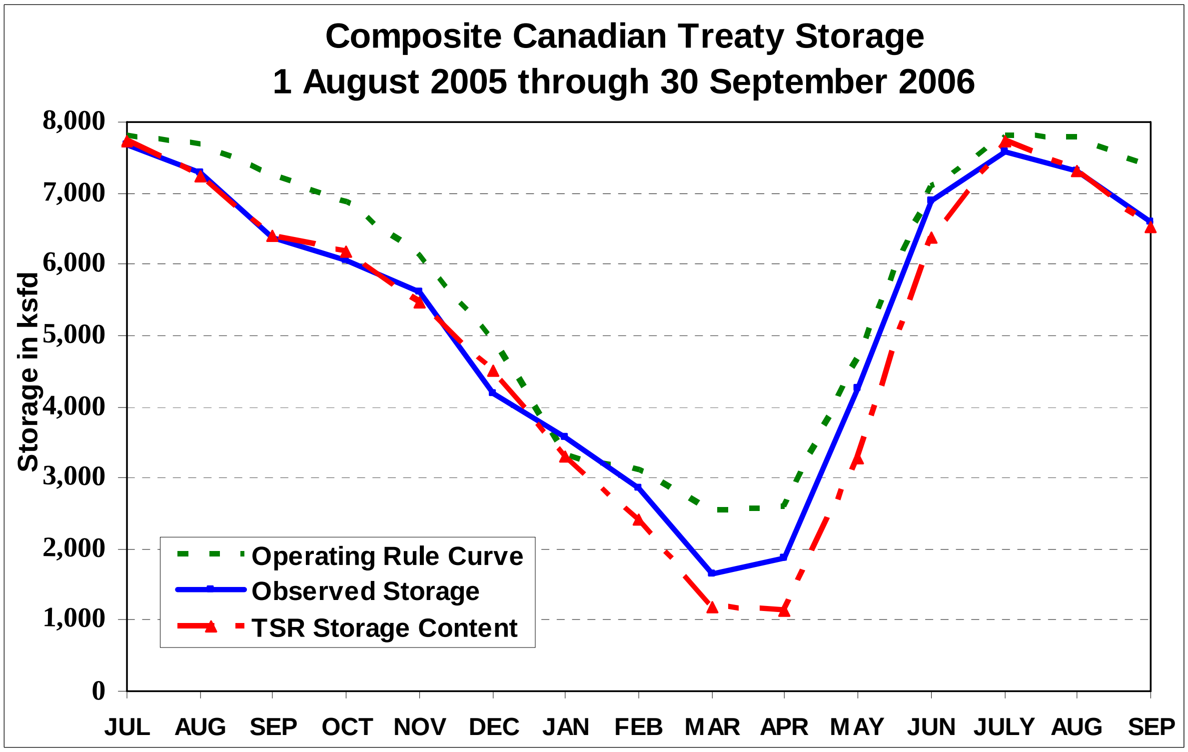
Power Generation and other Accomplishments

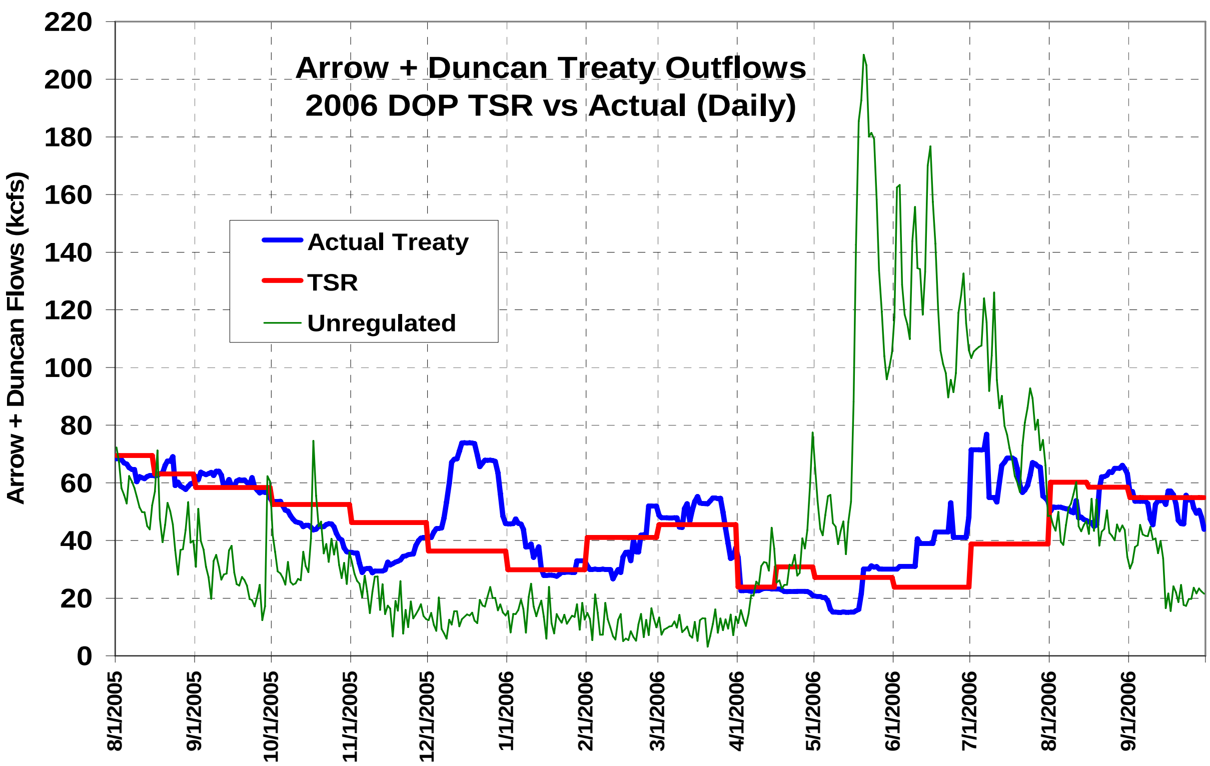
Actual U.S. power benefits from the operation of CRT storage are unknown and can only be roughly estimated. Treaty storage has such a large impact on the U.S. system operation that its absence would significantly affect operating procedures, non-power requirements, loads and resources, and market conditions, thus making any benefit analysis highly speculative. The following graph shows a rough estimate of the average monthly impact on downstream U.S. power generation during the 2005-2006 operating year, with and without the regulation of Canadian storage, based on the Pacific Northwest Coordination Agreement (PNCA) Actual Energy Regulation (AER) that includes minimum flow and spill requirements for U.S. fishery objectives. The increase in average annual U.S. power generation due to the operation of Canadian storage, as measured by the PNCA AER, was 649 aMW. In addition to the increase in average annual U.S. power generation, the Treaty regulation also shifted the timing of generation from the low value freshet period, into higher value winter months. No quantification of this benefit is provided in this report.



Based on the authority from the 2005-2006 and 2006-2007 DOPs, the Operating Committee completed supplemental operating agreements, described in Section III, which resulted in power and other benefits both in Canada and the U.S. Other benefits include changes to streamflows below Arrow that enhanced trout and mountain whitefish spawning in Canada and the downstream migration of salmon in the U.S.

The following chart compares the actual operation of the composite Canadian Treaty Storage to the results of the DOP TSR study, and the subsequent graph shows the difference in Arrow plus Duncan regulated outflows in the DOP TSR and the actual daily CRT outflows due to these agreements. The daily unregulated streamflow is also shown for comparison purposes.





At the beginning of the 2005-2006 operating year, the TSR storage level for Canadian storage was nearly full, and the actual Canadian storage was slightly below full at about 98.3% full.

In late September, under terms of the LCA, Canada released some LCA provisional draft which was returned in early November. As has occurred in several times in recent years, the TSR composite Treaty content changed significantly late in the month as a result of weather events. This occurred in October when the second TSR of the month increased the composite Treaty storage by 979 hm^3 (400 ksfd) resulting in a draft below TSR levels of about 306 hm^3 (125 ksfd). In both November and December large changes in streamflows between the last forecast used in the TSR and the observed streamflows used in the subsequent TSR also resulted in operations that deviated from that intended relative to the TSR. In November, the operation targeted the TSR content at the end of the month, however the final month-end contents were about 306 hm^3 (125 ksfd) above the TSR.

In December, Canada exercised their LCA provisional draft rights and drafted 306 hm^3 (125 ksfd) below TSR by the end of the month. However, because of a change in the TSR content of over 979 hm^3 (400 ksfd), Treaty storage ended the month 820 hm^3 (335 ksfd) below the TSR and 514 hm^3 (210 ksfd) below the target for the month. Also in December, the U.S. and Canada reached agreement to shape flows from December through July to meet multiple system requirements and fishery needs.

Beginning in late January and continuing through February 2006, the U.S. stored water for flow augmentation in Mica resulting in an Arrow discharge from about 991 m^3/s (35 kcfs) down to about 566 m^3/s (20 kcfs) for whitefish spawning. The storage level above TSR reached about 1,529 hm^3 (625 ksfd) in February as storage was being managed for flow augmentation and to maintain smooth flow patterns for whitefish. All LCA provisional draft was returned by the end of January.

In April, Arrow actual outflows were reduced to about 566 m^3/s (20 kcfs) to balance the needs of B.C. trout spawning, U.S. fisheries needs, and system load requirements, ending April with composite Treaty storage about 1,835 hm^3 (750 ksfd) above the DOP TSR. Arrow outflows were reduced in late May and June to due to the high inflows experienced into U.S. projects. Canadian Treaty storage ended May over 2,398 hm^3 (980 ksfd) above TSR levels. The balance of flow augmentation storage was released in July resulting in relatively high Arrow outflows to help meet U.S. fisheries' flows as inflows receded. The sum of Canadian Treaty storage ended July below DOP TSR levels due to both Canada's use of provisional draft under the LCA and to inflow forecast uncertainties during the month. Treaty projects remained slightly below TSR levels through August and September as the Canadian Entity exercised provisional draft totaling 206 hm^3 (84 ksfd) under the LCA.

VII - TABLES

Table 1: Unregulated Runoff Volume Forecasts, Most Probable 1-April through 31-August Forecasts for 2006

Million Acre-feet

First of Month Forecast	Duncan	Arrow	Mica	Libby	Columbia River at The Dalles, Oregon
January	1.84	20.60	9.94	5.50	87.50
February	1.91	20.10	9.67	6.25	94.30
March	1.97	21.00	10.00	6.09	91.20
April	1.93	21.00	10.00	5.92	92.70
May	1.94	20.80	9.85	6.06	95.60
June	1.98	21.40	10.10	6.28	96.50
Actual	2.11	21.36	10.89	6.28	97.54

Cubic Kilometers

First of Month Forecast	Duncan	Arrow	Mica	Libby	Columbia River at The Dalles, Oregon
January	2.26	25.32	12.22	6.76	107.54
February	2.35	24.70	11.88	7.68	115.89
March	2.42	25.81	12.29	7.48	112.08
April	2.37	25.81	12.29	7.28	113.93
May	2.38	25.56	12.11	7.45	117.49
June	2.43	26.30	12.41	7.72	118.60
Actual	2.60	26.26	13.39	8.15	119.88

Table 2: 2006 Variable Refill Curve for Mica Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KAF			8241.4	7979.6	8100.6	7830.9	7154.5	4927.0
PROBABLE DATE-31JULY INFLOW, KSFD	**		4155.0	4023.0	4084.0	3948.0	3607.0	2484.0
95% FORECAST ERROR FOR DATE, KSFD			653.0	510.4	465.4	444.5	360.5	360.5
95% CONF.DATE-31JULY INFLOW, KSFD	1/		3502.0	3512.6	3618.6	3503.5	3246.5	2123.5
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		3502.0					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		2170.0					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		2197.2					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		2443.8					
JAN31 ORC, FT	7/		2431.5					
BASE ECC, FT	8/	2431.3						
LOWER LIMIT, FT		2401.7						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.6	97.6				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		3417.9	3428.3				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		2086.0	2086.0				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		2197.3	2186.9				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		2443.8	2443.6				
FEB28 ORC, FT	7/		2427.7	2427.7				
BASE ECC, FT	8/	2427.7						
LOWER LIMIT, FT		2395.4						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.1	95.1	97.4			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		3330.4	3340.4	3524.5			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		3000.0	3000.0	3000.0			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		1993.0	1993.0	1993.0			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		2191.8	2181.8	1997.7			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		2443.7	2443.5	2439.6			
MAR31 ORC, FT	7/		2427.8	2427.8	2427.8			
BASE ECC, FT	8/	2427.8						
LOWER LIMIT, FT		2394.1						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			90.0	90.0	92.2	94.7		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		3151.8	3161.3	3336.4	3317.8		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		5000.0	5000.0	5000.0	5000.0		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		1873.0	1873.0	1873.0	1873.0		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		2250.4	2240.9	2065.8	2084.4		
VRC APR30 RESERVOIR CONTENT, FEET	6/		2444.9	2444.7	2441.0	2441.4		
APR30 ORC, FT	7/		2428.3	2428.3	2428.3	2428.3		
BASE ECC, FT	8/	2428.3						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			71.6	71.6	73.3	75.3	79.5	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		2507.4	2515.0	2652.4	2638.1	2581.0	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		18000.0	18000.0	18000.0	18000.0	18000.0	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		1718.0	1718.0	1718.0	1718.0	1718.0	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		2739.8	2732.2	2594.8	2609.1	2666.2	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		2454.7	2454.6	2451.9	2452.2	2453.3	
MAY31 ORC, FT	7/		2444.8	2444.8	2444.8	2444.8	2444.8	
BASE ECC, FT	8/	2444.8						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			35.5	35.5	36.3	37.3	39.4	49.5
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		1243.2	1247.0	1313.6	1306.8	1279.1	1051.1
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		38000.0	38000.0	38000.0	38000.0	38000.0	38000.0
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		1178.0	1178.0	1178.0	1178.0	1178.0	1178.0
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		3464.0	3460.2	3393.6	3400.4	3428.1	3529.2
VRC JUN30 RESERVOIR CONTENT, FEET	6/		2468.8	2468.7	2467.5	2467.6	2468.2	2470.0
JUN30 ORC, FT	7/		2466.3	2466.3	2466.3	2466.3	2466.3	2466.3
BASE ECC, FT	8/	2466.3						
JUL 31 ORC, FT			2470.1	2470.1	2470.1	2470.1	2470.1	2470.1

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW).
2/ PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS.
4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
5/ FULL CONTENT (3529.2 KSFD) PLUS 4/ MINUS /2.
6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE
7/ LOWER OF ELEV. FROM 6/ OR BASE ECC (INTIAL), BUT NOT LESS THAN LOWER LIMIT OR MORE THAN FLOOD CONTROL.
8/ HIGHER OF ARC OR CRC1 IN DOP

Table 2M: 2006 Variable Refill Curve for Mica Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, km3			10.17	9.84	9.99	9.66	8.82	6.08
PROBABLE DATE-31JULY INFLOW, hm3	**		10165.62	9842.67	9991.91	9659.18	8824.89	6077.35
95% FORECAST ERROR FOR DATE, hm3			1597.69	1248.86	1138.62	1087.61	881.94	881.94
95% CONF.DATE-31JULY INFLOW, hm3	1/		8567.99	8593.93	8853.27	8571.66	7942.89	5195.36
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.00					
ASSUMED FEB1-JUL31 INFLOW, hm3	2/		8567.99					
FEB MINIMUM FLOW REQUIREMENT, m3/s	3/		84.95					
MIN FEB1-JUL31 OUTFLOW, hm3	4/		5309.12					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		5375.67					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		744.87					
JAN31 ORC, m	7/		741.12					
BASE ECC, m	8/	741.06						
LOWER LIMIT, m		732.04						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.60	97.60				
ASSUMED MAR1-JUL31 INFLOW, hm3	2/		8362.23	8387.68				
MAR MINIMUM FLOW REQUIREMENT, m3/s	3/		84.95	84.95				
MIN MAR1-JUL31 OUTFLOW, hm3	4/		5103.61	5103.61				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		5375.91	5350.47				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		744.87	744.81				
FEB28 ORC, m	7/		739.96	739.96				
BASE ECC, m	8/	739.96						
LOWER LIMIT, m		730.12						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.10	95.10	97.40			
ASSUMED APR1-JUL31 INFLOW, hm3	2/		8148.16	8172.62	8623.04			
APR MINIMUM FLOW REQUIREMENT, m3/s	3/		84.95	84.95	84.95			
MIN APR1-JUL31 OUTFLOW, hm3	4/		4876.07	4876.07	4876.07			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		5362.46	5337.99	4887.57			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		744.84	744.78	743.59			
MAR31 ORC, m	7/		739.99	739.99	739.99			
BASE ECC, m	8/	739.99						
LOWER LIMIT, m		729.72						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			90.00	90.00	92.20	94.70		
ASSUMED MAY1-JUL31 INFLOW, hm3	2/		7711.19	7734.44	8162.84	8117.33		
MAY MINIMUM FLOW REQUIREMENT, m3/s	3/		141.58	141.58	141.58	141.58		
MIN MAY1-JUL31 OUTFLOW, hm3	4/		4582.48	4582.48	4582.48	4582.48		
VRC APR30 RESERVOIR CONTENT, hm3	5/		5505.83	5482.59	5054.19	5099.69		
VRC APR30 RESERVOIR CONTENT, METERS	6/		745.21	745.14	744.02	744.14		
APR30 ORC, m	7/		740.15	740.15	740.15	740.15		
BASE ECC, m	8/	740.15						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			71.60	71.60	73.30	75.30	79.50	
ASSUMED JUN1-JUL31 INFLOW, hm3	2/		6134.60	6153.20	6489.36	6454.38	6314.67	
JUN MINIMUM FLOW REQUIREMENT, m3/s	3/		509.70	509.70	509.70	509.70	509.70	
MIN JUN1-JUL31 OUTFLOW, hm3	4/		4203.26	4203.26	4203.26	4203.26	4203.26	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		6703.19	6684.60	6348.44	6383.42	6523.12	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		748.19	748.16	747.34	747.43	747.77	
MAY31 ORC, m	7/		745.18	745.18	745.18	745.18	745.18	
BASE ECC, m	8/	745.18						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			35.50	35.50	36.30	37.30	39.40	49.50
ASSUMED JUL1-JUL31 INFLOW, hm3	2/		3041.61	3050.91	3213.85	3197.22	3129.45	2571.62
JUL MINIMUM FLOW REQUIREMENT, m3/s	3/		1076.04	1076.04	1076.04	1076.04	1076.04	1076.04
MIN JUL1-JUL31 OUTFLOW, hm3	4/		2882.09	2882.09	2882.09	2882.09	2882.09	2882.09
VRC JUN30 RESERVOIR CONTENT, hm3	5/		8475.02	8465.73	8302.78	8319.42	8387.19	8634.54
VRC JUN30 RESERVOIR CONTENT, METERS	6/		752.49	752.46	752.09	752.12	752.31	752.86
JUN30 ORC, m	7/		751.73	751.73	751.73	751.73	751.73	751.73
BASE ECC, m	8/	751.73						
JUL 31 ORC, m			752.89	752.89	752.89	752.89	752.89	752.89

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW).
2/ PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS.
4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
5/ FULL CONTENT (8634.54 hm3) PLUS 4/ MINUS /2.
6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE
7/ LOWER OF ELEV. FROM 6/ OR BASE ECC (INTIAL), BUT NOT LESS THAN LOWER LIMIT OR MORE THAN FLOOD CONTROL.

Table 3: 2006 Variable Refill Curve for Arrow Reservoir

		INITIAL	JAN 1 Total	FEB 1 Total	MAR 1 Total	APR 1 Total	MAY 1 Total	JUN 1 Total
ABLE DATE-31JULY INFLOW, KAF			18901.8	18023.3	18229.4	1717.5	15779.1	10142.2
& IN KSFD	**		9529.5	9086.6	9190.5	865.9	7955.2	5113.3
95% FORECAST ERROR FOR DATE, IN KSFD			1233.4	987.3	825.2	715.6	501.7	501.7
95% CONF.DATE-31JULY INFLOW, KSFD	1/		8026.1	8099.3	8365.3	8150.3	7453.5	4611.6
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		8026.1					
MIN FEB1-JUL31 OUTFLOW, KSFD	3/		3956.0					
UPSTREAM DISCHARGE, KSFD	4/		1921.7					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		1431.2					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		1408.0					
JAN31 ORC, FT	7/		1408.0					
BASE ECC, FT	8/	1408.5						
LOWER LIMIT, FT		1384.4						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.5	97.5				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		7825.4	7896.8				
MIN MAR1-JUL31 OUTFLOW, KSFD	3/		3816.0	3816.0				
UPSTREAM DISCHARGE, KSFD	4/		2089.1	2089.1				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		1659.3	1587.9				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		1412.2	1410.9				
FEB28 ORC, FT	7/		1410.3	1410.3				
BASE ECC, FT	8/	1410.3						
LOWER LIMIT, FT		1379.0						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			94.4	94.4	96.9			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		7576.6	7645.8	8106.0			
MIN APR1-JUL31 OUTFLOW, KSFD	3/		3661.0	3661.0	3661.0			
UPSTREAM DISCHARGE, KSFD	4/		2082.4	2082.4	2082.4			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		1746.4	1677.2	1217.0			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		1413.8	1412.5	1403.9			
MAR31 ORC, FT	7/		1399.9	1399.9	1399.9			
BASE ECC, FT	8/	1410.5						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			87.5	87.5	89.8	92.6		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		7022.8	7086.9	7512.0	7547.2		
MIN MAY1-JUL31 OUTFLOW, KSFD	3/		3511.0	3511.0	3511.0	3511.0		
UPSTREAM DISCHARGE, KSFD	4/		2060.0	2060.0	2060.0	2060.0		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		2127.8	2063.7	1638.6	1603.4		
VRC APR30 RESERVOIR CONTENT, FEET	6/		1420.5	1419.4	1411.8	1411.2		
APR30 ORC, FT	7/		1399.9	1399.9	1399.9	1399.9		
BASE ECC, FT	8/	1413.3						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL			65.5	65.5	67.2	69.3	74.9	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		5257.1	5305.1	5621.5	5648.2	5582.7	
MIN JUN1-JUL31 OUTFLOW, KSFD	3/		3356.0	3356.0	3356.0	3356.0	3356.0	
UPSTREAM DISCHARGE, KSFD	4/		1283.1	1283.1	1283.1	1283.1	1283.1	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		2961.6	2913.6	2597.2	2570.5	2636.0	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		1434.4	1433.6	1428.4	1428.0	1429.1	
MAY31 ORC, FT	7/		1425.6	1425.6	1425.6	1425.6	1425.6	
BASE ECC, FT	8/	1425.5						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			30.3	30.3	31.1	32.1	34.7	46.3
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		2431.9	2454.1	2601.6	2616.3	2586.4	2135.2
MIN JUL1-JUL31 OUTFLOW, KSFD	3/		1736.0	1736.0	1736.0	1736.0	1736.0	1736.0
UPSTREAM DISCHARGE, KSFD	4/		199.7	199.7	199.7	199.7	199.7	199.7
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		3083.4	3061.2	2913.7	2899.0	2928.9	3380.1
VRC JUN30 RESERVOIR CONTENT, FEET	6/		1436.3	1435.9	1433.6	1433.4	1433.8	1438.1
JUN30 ORC, FT	7/		1436.3	1435.9	1433.6	1433.4	1433.8	1438.1
BASE ECC, FT	8/	1438.1						
JUL 31 ECC, FT			1444.0	1444.0	1444.0	1444.0	1444.0	1444.0

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW).
2/ PRECEEDING LINE TIMES 1/.
3/ CUMMULATIVE MINIMUM OUTFLOW FROM DATE TO JULY, USING POWER DISCHARGE REQUIREMENTS
4/ UPSTREAM DISCHARGE REQUIREMENT.
5/ MAXIMUM (FULL CONTENT (3579.6 KSFD) MINUS 2/ PLUS 3/ MINUS /4 OR LOWER LIMIT)
6/ ELEV. FROM 5/, INTERP. FROM STORAGE CONTENT TABLE
7/ LOWER OF ELEV. FROM 6/ OR BASE ECC (INTIAL), BUT NOT LESS THAN LOWER LIMIT OR MORE THAN FLOOD CONTROL.
8/ HIGHER OF THE ARC OR CRC1 IN DOP

Table 3M: 2006 Variable Refill Curve for Arrow Reservoir

		INITIAL	JAN 1 Total	FEB 1 Total	MAR 1 Total	APR 1 Total	MAY 1 Total	JUN 1 Total
PROBABLE DATE-31JULY INFLOW, km3			23.31	22.23	22.49	2.12	19.46	12.51
& IN hm3	**		23314.87	22231.28	22485.48	2118.51	19463.19	12510.20
95% FORECAST ERROR FOR DATE, IN hm3			3017.67	2415.45	2018.91	1750.71	1227.47	1227.47
95% CONF.DATE-31JULY INFLOW, hm3	1/		19636.66	19815.75	20466.54	19940.52	18235.73	11282.74
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.00					
ASSUMED FEB1-JUL31 INFLOW, hm3	2/		19636.6563					
MIN FEB1-JUL31 OUTFLOW, hm3	3/		9678.75					
UPSTREAM DISCHARGE, hm3	4/		4701.63					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		3501.57					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		429.16					
JAN31 ORC, m	7/		429.16					
BASE ECC, m	8/	429.31						
LOWER LIMIT, m		421.97						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.50	97.50				
ASSUMED MAR1-JUL31 INFLOW, hm3	2/		19145.62	19320.31				
MIN MAR1-JUL31 OUTFLOW, hm3	3/		9336.23	9336.23				
UPSTREAM DISCHARGE, hm3	4/		5111.19	5111.19				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		3501.57	3884.96				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		430.44	430.04				
FEB28 ORC, m	7/		429.86	429.86				
BASE ECC, m	8/	429.86						
LOWER LIMIT, m		420.32						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			94.40	94.40	96.90			
ASSUMED APR1-JUL31 INFLOW, hm3	2/		18536.91	18706.21	19832.14			
MIN APR1-JUL31 OUTFLOW, hm3	3/		8957.00	8957.00	8957.00			
UPSTREAM DISCHARGE, hm3	4/		5094.80	5094.80	5094.80			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		3501.57	4103.44	2977.51			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		430.93	430.53	427.91			
MAR31 ORC, m	7/		426.69	426.69	426.69			
BASE ECC, m	8/	429.92						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			87.50	87.50	89.80	92.60		
ASSUMED MAY1-JUL31 INFLOW, hm3	2/		17181.98	17338.81	18378.86	18464.98		
MIN MAY1-JUL31 OUTFLOW, hm3	3/		8590.01	8590.01	8590.01	8590.01		
UPSTREAM DISCHARGE, hm3	4/		5040.00	5040.00	5040.00	5040.00		
VRC APR30 RESERVOIR CONTENT, hm3	5/		3501.57	5049.05	4009.00	3922.88		
VRC APR30 RESERVOIR CONTENT, METERS	6/		432.97	432.63	430.32	430.13		
APR30 ORC, Fm	7/		426.69	426.69	426.69	426.69		
BASE ECC, m	8/	430.77						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL			65.50	65.50	67.20	69.30	74.90	
ASSUMED JUN1-JUL31 INFLOW, hm3	2/		12862.02	12979.46	13753.56	13818.89	13658.63	
MIN JUN1-JUL31 OUTFLOW, hm3	3/		8210.79	8210.79	8210.79	8210.79	8210.79	
UPSTREAM DISCHARGE, hm3	4/		3139.23	3139.23	3139.23	3139.23	3139.23	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		3501.57	7128.41	6354.31	6288.99	6449.24	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		437.21	436.96	435.38	435.25	435.59	
MAY31 ORC, m	7/		434.52	434.52	434.52	434.52	434.52	
BASE ECC, m	8/	434.49						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			30.30	30.30	31.10	32.10	34.70	46.30
ASSUMED JUL1-JUL31 INFLOW, hm3	2/		5949.89	6004.20	6365.07	6401.04	6327.89	5223.98
MIN JUL1-JUL31 OUTFLOW, hm3	3/		4247.30	4247.30	4247.30	4247.30	4247.30	4247.30
UPSTREAM DISCHARGE, hm3	4/		488.59	488.59	488.59	488.59	488.59	488.59
VRC JUN30 RESERVOIR CONTENT, hm3	5/		3501.57	7489.53	7128.66	7092.69	7165.85	8269.75
VRC JUN30 RESERVOIR CONTENT, METERS	6/		437.78	437.66	436.96	436.90	437.02	438.33
JUN30 ORC, m	7/		437.78	437.66	436.96	436.90	437.02	438.33
BASE ECC, m	8/	438.33						
JUL 31 ECC, m			440.13	440.13	440.13	440.13	440.13	440.13

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW).
2/ PRECEEDING LINE TIMES 1/.
3/ CUMMULATIVE MINIMUM OUTFLOW FROM DATE TO JULY, USING POWER DISCHARGE REQUIREMENTS
4/ UPSTREAM DISCHARGE REQUIREMENT.
5/ MAXIMUM(FULL CONTENT (8757.85 hm3) MINUS 2/ PLUS 3/ MINUS /4 OR LOWER LIMIT)
6/ ELEV. FROM 5/, INTERP. FROM STORAGE CONTENT TABLE
7/ LOWER OF ELEV. FROM 6/ OR BASE ECC (INTIAL), BUT NOT LESS THAN LOWER LIMIT OR MORE THAN FLOOD CONTROL.

Table 4: 2006 Variable Refill Curve for Duncan Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KAF			1578.9	1636.4	1634.4	1572.9	1432.1	892.6
& IN KSFD	**		796.0	825.0	824.0	793.0	722.0	450.0
95% FORECAST ERROR FOR DATE, IN KSFD			118.4	108.9	97.5	88.1	73.3	73.3
95% CONF.DATE-31JULY INFLOW, KSFD	1/		677.6	716.1	726.5	704.9	648.7	376.7
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		677.6					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		100.0					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		233.2					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		261.4					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		1837.6					
JAN31 ORC, FT	7/		1837.6					
BASE ECC, FT	8/	1856.3						
LOWER LIMIT, FT		1802.2						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.8	97.8				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		662.7	700.3				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		230.4	230.4				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		273.5	235.9				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		1839.3	1834.1				
FEB28 ORC, FT	7/		1821.2	1815.8				
BASE ECC, FT	8/	1833.8						
LOWER LIMIT, FT		1795.3						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.3	95.3	97.4			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		645.8	682.4	707.6			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		100.0	100.0	100.0			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		227.3	227.3	227.3			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		287.3	250.7	225.5			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		1841.2	1836.2	1832.7			
MAR31 ORC, FT	7/		1821.2	1815.8	1812.5			
BASE ECC, FT	8/	1828.2						
LOWER LIMIT, FT		1795.1						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			89.2	89.2	91.1	93.5		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		604.5	638.7	661.8	659.1		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		1800.0	1800.0	1800.0	1800.0		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		224.3	224.3	224.3	224.3		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		325.6	291.4	268.3	271.0		
VRC APR30 RESERVOIR CONTENT, FEET	6/		1846.3	1841.7	1838.6	1839.0		
APR30 ORC, FT	7/		1821.2	1815.8	1812.5	1814.3		
BASE ECC, FT	8/	1831.3						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			67.6	67.6	69.1	70.9	75.8	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		458.1	484.1	502.0	499.8	491.7	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		2000.0	2000.0	2000.0	2000.0	2000.0	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		168.5	168.5	168.5	168.5	168.5	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		416.2	390.2	372.3	374.5	382.6	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		1857.9	1854.6	1852.3	1852.6	1853.6	
MAY31 ORC, FT	7/		1846.7	1846.7	1846.7	1846.7	1846.7	
BASE ECC, FT	8/	1846.7						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			31.7	31.7	32.4	33.3	35.6	46.9
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		214.8	227.0	235.4	234.7	230.9	176.7
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		3500.0	3500.0	3500.0	3500.0	3500.0	3500.0
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		108.5	108.5	108.5	108.5	108.5	108.5
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		599.5	587.3	578.9	579.6	583.4	637.6
VRC JUN30 RESERVOIR CONTENT, FEET	6/		1879.9	1878.5	1877.4	1878.5	1878.0	1884.2
JUN30 ORC, FT	7/		1875.7	1875.7	1875.7	1875.7	1875.7	1875.7
BASE ECC, FT	8/	1875.7						
JUL 31 ECC, FT			1892.0	1892.0	1892.0	1892.0	1892.0	1892.0

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW).
2/ PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS.
4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/, DATE TO JULY.
5/ FULL CONTENT (705.8 KSFD) PLUS 4/ MINUS /2.
6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE.
7/ LOWER OF ELEV. FROM 6/ OR BASE ECC (INTIAL), BUT NOT LESS THAN LOWER LIMIT OR MORE THAN FLOOD CONTROL.
8/ HIGHER OF ARC OR CRC1 IN DOP

Table 4M: 2006 Variable Refill Curve for Duncan Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, km3			1.95	2.02	2.02	1.94	1.77	1.10
& IN hm3	**		1947.49	2018.45	2016.00	1940.15	1766.45	1100.97
95% FORECAST ERROR FOR DATE, IN hm3			289.59	266.56	238.58	215.55	179.35	179.35
95% CONF.DATE-31JULY INFLOW, hm3	1/		1657.82	1752.01	1777.45	1724.61	1587.11	921.63
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			100.00					
ASSUMED FEB1-JUL31 INFLOW, hm3	2/		1657.82					
FEB MINIMUM FLOW REQUIREMENT, m3/s	3/		2.83					
MIN FEB1-JUL31 OUTFLOW, hm3	4/		570.55					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		639.54					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		560.10					
JAN31 ORC, m	7/		560.10					
BASE ECC, m	8/	565.80						
LOWER LIMIT, m		549.31						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			97.80	97.80				
ASSUMED MAR1-JUL31 INFLOW, hm3	2/		662.70	700.30				
MAR MINIMUM FLOW REQUIREMENT, m3/s	3/		244.66	244.66				
MIN MAR1-JUL31 OUTFLOW, hm3	4/		6.52	6.52				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		669.15	577.15				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		4500.03	4487.31				
FEB28 ORC, m	7/		555.10	553.46				
BASE ECC, m	8/	558.94						
LOWER LIMIT, m		547.21						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			95.30	95.30	97.40			
ASSUMED APR1-JUL31 INFLOW, hm3	2/		645.80	682.40	707.60			
APR MINIMUM FLOW REQUIREMENT, m3/s	3/		244.66	244.66	244.66			
MIN APR1-JUL31 OUTFLOW, hm3	4/		6.44	6.44	6.44			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		702.91	613.36	551.71			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		4504.68	4492.45	4483.88			
MAR31 ORC, m	7/		555.10	553.46	552.45			
BASE ECC, m	8/	557.24						
LOWER LIMIT, m		547.15						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			89.20	89.20	91.10	93.50		
ASSUMED MAY1-JUL31 INFLOW, hm3	2/		604.50	638.70	661.80	659.10		
MAY MINIMUM FLOW REQUIREMENT, m3/s	3/		4403.88	4403.88	4403.88	4403.88		
MIN MAY1-JUL31 OUTFLOW, hm3	4/		6.35	6.35	6.35	6.35		
VRC APR30 RESERVOIR CONTENT, hm3	5/		796.61	712.94	656.42	663.03		
VRC APR30 RESERVOIR CONTENT, METERS	6/		4517.16	4505.90	4498.32	4499.30		
APR30 ORC, m	7/		555.10	553.46	552.45	553.00		
BASE ECC, m	8/	558.18						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			67.60	67.60	69.10	70.90	75.80	
ASSUMED JUN1-JUL31 INFLOW, hm3	2/		458.10	484.10	502.00	499.80	491.70	
JUN MINIMUM FLOW REQUIREMENT, m3/s	3/		4893.20	4893.20	4893.20	4893.20	4893.20	
MIN JUN1-JUL31 OUTFLOW, hm3	4/		4.77	4.77	4.77	4.77	4.77	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		1018.27	954.66	910.87	916.25	936.07	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		4545.54	4537.46	4531.84	4532.57	4535.02	
MAY31 ORC, m	7/		562.87	562.87	562.87	562.87	562.87	
BASE ECC, m	8/	562.87						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			31.70	31.70	32.40	33.30	35.60	46.90
ASSUMED JUL1-JUL31 INFLOW, hm3	2/		214.80	227.00	235.40	234.70	230.90	176.70
JUL MINIMUM FLOW REQUIREMENT, m3/s	3/		8563.10	8563.10	8563.10	8563.10	8563.10	8563.10
MIN JUL1-JUL31 OUTFLOW, hm3	4/		3.07	3.07	3.07	3.07	3.07	3.07
VRC JUN30 RESERVOIR CONTENT, hm3	5/		1466.74	1436.89	1416.34	1418.05	1427.35	1559.95
VRC JUN30 RESERVOIR CONTENT, METERS	6/		4599.36	4595.94	4593.25	4595.94	4594.71	4609.88
JUN30 ORC, m	7/		571.71	571.71	571.71	571.71	571.71	571.71
BASE ECC, m	8/	571.71						
JUL 31 ECC, m			576.68	576.68	576.68	576.68	576.68	576.68

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW).
2/ PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS.
4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
5/ FULL CONTENT (1726.81 hm3) PLUS 4/ MINUS /2.
6/ ELEV FROM 5/,INTERP FROM STORAGE CONTENT TABLE.
7/ LOWER OF ELEV. FROM 6/ OR BASE ECC (INTIAL), BUT NOT LESS THAN LOWER LIMIT OR MORE THAN FLOOD CONTROL.

Table 5: 2006 Variable Refill Curve for Libby Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, KAF			5513.0	6215.0	6513.0	6228.0	6322.0	6857.0
PROBABLE DATE-31JULY INFLOW, KSFD			2779.5	3133.4	3283.6	3139.9	3187.3	3457.1
95% FORECAST ERROR FOR DATE, KSFD			637.8	478.5	447.7	433.6	392.2	376.6
OBSERVED JAN1-DATE INFLOW, IN KSFD			0.0	148.2	238.5	350.4	663.5	1859.9
95% CONF.DATE-31JULY INFLOW, KSFD	1/		2141.7	2506.7	2597.5	2356.0	2131.6	1220.6
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			96.9					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		2075.3					
FEB MINIMUM FLOW REQUIREMENT, CFS	3/		4000.0					
MIN FEB1-JUL31 OUTFLOW, KSFD	4/		1337.0					
VRC JAN31 RESERVOIR CONTENT, KSFD	5/		1772.2					
VRC JAN31 RESERVOIR CONTENT, FEET	6/		2425.0					
JAN31 ORC, FT	7/		2413.9					
BASE ECC, FT	9/	2413.9						
LOWER LIMIT, FT		2371.2						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			94.1	97.1				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		2015.3	2434.0				
MAR MINIMUM FLOW REQUIREMENT, CFS	3/		4000.0	4000.0				
MIN MAR1-JUL31 OUTFLOW, KSFD	4/		1225.0	1225.0				
VRC FEB28 RESERVOIR CONTENT, KSFD	5/		1720.2	1301.5				
VRC FEB28 RESERVOIR CONTENT, FEET	6/		2422.4	2399.5				
FEB28 ORC, FT	7/		2411.1	2399.5				
BASE ECC, FT	9/	2413.9						
LOWER LIMIT, FT		2371.2						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			90.6	93.5	96.3			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		1940.4	2343.8	2501.4			
APR MINIMUM FLOW REQUIREMENT, CFS	3/		4000.0	4000.0	4000.0			
MIN APR1-JUL31 OUTFLOW, KSFD	4/		1101.0	1101.0	1101.0			
VRC MAR31 RESERVOIR CONTENT, KSFD	5/		1671.1	1267.7	1110.1			
VRC MAR31 RESERVOIR CONTENT, FEET	6/		2420.0	2397.3	2387.1			
MAR31 ORC, FT	7/		2408.2	2397.3	2387.1			
BASE ECC, FT	9/	2411.1						
LOWER LIMIT, FT		2320.8						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			82.4	85.0	87.6	93.8		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		1764.8	2130.7	2275.4	2209.9		
MAY MINIMUM FLOW REQUIREMENT, CFS	3/		10000.0	10000.0	10000.0	10000.0		
MIN MAY1-JUL31 OUTFLOW, KSFD	4/		981.0	981.0	981.0	981.0		
VRC APR30 RESERVOIR CONTENT, KSFD	5/		1726.7	1360.8	1216.1	1281.6		
VRC APR30 RESERVOIR CONTENT, FEET	6/		2422.7	2402.9	2394.0	2398.2		
APR30 ORC, FT	7/		2399.5	2399.5	2394.0	2398.2		
BASE ECC, FT	9/	2399.5						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			55.2	57.0	58.7	62.9	67.0	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		1182.2	1428.8	1524.7	1481.9	1428.2	
JUN MINIMUM FLOW REQUIREMENT, CFS	3/		11000.0	11000.0	11000.0	11000.0	1000.0	
MIN JUN1-JUL31 OUTFLOW, KSFD	4/		671.0	671.0	671.0	671.0	671.0	
VRC MAY31 RESERVOIR CONTENT, KSFD	5/		1999.3	1752.7	1656.8	1699.6	1753.3	
VRC MAY31 RESERVOIR CONTENT, FEET	6/		2436.0	2424.0	2419.2	2421.4	2424.1	
MAY31 ORC, FT	7/		2424.2	2424.0	2419.2	2421.4	2424.1	
BASE ECC, FT	9/	2424.2						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			19.7	20.4	21.0	22.5	24.0	35.8
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		421.9	511.4	545.5	530.1	511.6	437.0
JUL MINIMUM FLOW REQUIREMENT, CFS	3/		11000.0	11000.0	11000.0	11000.0	1000.0	11000.0
MIN JUL1-JUL31 OUTFLOW, KSFD	4/		341.0	341.0	341.0	341.0	341.0	341.0
VRC JUN30 RESERVOIR CONTENT, KSFD	5/		2429.6	2340.1	2306.0	2321.4	2339.9	2414.5
VRC JUN30 RESERVOIR CONTENT, FEET	6/		2455.5	2451.6	2450.1	2450.8	2451.6	2454.8
JUN30 ORC, FT	7/		2455.5	2451.6	2450.1	2450.8	2451.6	2454.8
BASE ECC, FT	9/	2459.0						
JUL 31 ORC, FT			2459.0	2459.0	2459.0	2459.0	2459.0	2459
JAN1-JUL31 FORECAST,-EARLYBIRD,MAF	8/		101.0	111.0	107.0	107.0	110.0	111.0

1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW) MINUS OBSERVED INFLOW.
2/ PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS. 4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
5/ FULL CONTENT (2510.5 KSFD) PLUS 4/ MINUS /2.
6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE.A143
7/ LOWER OF ELEV. FROM 6/ OR BASE VRC DETERMINED PRIOR TO YEAR (INTIAL),BUT NOT LESS THAN LOWER LIMIT
8/ MEASURED AT THE DALLES USED TO CALCULATE THE POWER DISCHARGE REQUIREMENTS FOR 3/.
9/ HIGHER OF ARC OR CRC1 IN DOP

Table 5M - 2006 Variable Refill Curve for Libby Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW, km3			6.80	7.67	8.03	7.68	7.80	8.46
PROBABLE DATE-31JULY INFLOW, hm3			6800.32	7666.18	8033.66	7682.08	7798.05	8458.14
95% FORECAST ERROR FOR DATE, hm3			1560.44	1170.70	1095.34	1060.85	959.56	921.39
OBSERVED JAN1-DATE INFLOW, IN hm3			0.00	362.59	583.51	857.29	1623.32	4550.43
95% CONF.DATE-31JULY INFLOW, hm3	1/		5239.88	6132.89	6355.04	5764.19	5215.17	2986.32
ASSUMED FEB1-JUL31 INFLOW, % OF VOL.			96.90					
ASSUMED FEB1-JUL31 INFLOW, hm3	2/		5077.43					
FEB MINIMUM FLOW REQUIREMENT, m3/s	3/		113.27					
MIN FEB1-JUL31 OUTFLOW, hm3	4/		3271.10					
VRC JAN31 RESERVOIR CONTENT, hm3	5/		4335.86					
VRC JAN31 RESERVOIR CONTENT, METERS	6/		739.14					
JAN31 ORC, m	7/		735.76					
BASE ECC, m	9/	735.76						
LOWER LIMIT, m		722.74						
ASSUMED MAR1-JUL31 INFLOW, % OF VOL.			94.10	97.10				
ASSUMED MAR1-JUL31 INFLOW, hm3	2/		4930.63	5955.02				
MAR MINIMUM FLOW REQUIREMENT, m3/s	3/		113.27	113.27				
MIN MAR1-JUL31 OUTFLOW, hm3	4/		2997.09	2997.09				
VRC FEB28 RESERVOIR CONTENT, hm3	5/		4208.64	3184.25				
VRC FEB28 RESERVOIR CONTENT, METERS	6/		738.35	731.37				
FEB28 ORC, m	7/		734.90	731.37				
BASE ECC, m	9/	735.76						
LOWER LIMIT, m		722.74						
ASSUMED APR1-JUL31 INFLOW, % OF VOL.			90.60	93.50	96.30			
ASSUMED APR1-JUL31 INFLOW, hm3	2/		4747.38	5734.34	6119.93			
APR MINIMUM FLOW REQUIREMENT, m3/s	3/		113.27	113.27	113.27			
MIN APR1-JUL31 OUTFLOW, hm3	4/		2693.71	2693.71	2693.71			
VRC MAR31 RESERVOIR CONTENT, hm3	5/		4088.51	3101.55	2715.97			
VRC MAR31 RESERVOIR CONTENT, METERS	6/		737.62	730.70	727.59			
MAR31 ORC, m	7/		734.02	730.70	727.59			
BASE ECC, m	9/	734.90						
LOWER LIMIT, m		707.38						
ASSUMED MAY1-JUL31 INFLOW, % OF VOL.			82.40	85.00	87.60	93.80		
ASSUMED MAY1-JUL31 INFLOW, hm3	2/		4317.76	5212.97	5566.99	5406.74		
MAY MINIMUM FLOW REQUIREMENT, m3/s	3/		283.17	283.17	283.17	283.17		
MIN MAY1-JUL31 OUTFLOW, hm3	4/		2400.11	2400.11	2400.11	2400.11		
VRC APR30 RESERVOIR CONTENT, hm3	5/		4224.54	3329.33	2975.31	3135.56		
VRC APR30 RESERVOIR CONTENT, METERS	6/		738.44	732.40	729.69	730.97		
APR30 ORC, m	7/		731.37	731.37	729.69	730.97		
BASE ECC, m	9/	731.37						
ASSUMED JUN1-JUL31 INFLOW, % OF VOL.			55.20	57.00	58.70	62.90	67.00	
ASSUMED JUN1-JUL31 INFLOW, hm3	2/		2892.37	3495.70	3730.33	3625.62	3494.23	
JUN MINIMUM FLOW REQUIREMENT, m3/s	3/		311.49	311.49	311.49	311.49	28.32	
MIN JUN1-JUL31 OUTFLOW, hm3	4/		1641.67	1641.67	1641.67	1641.67	1641.67	
VRC MAY31 RESERVOIR CONTENT, hm3	5/		4891.49	4288.16	4053.53	4158.24	4289.62	
VRC MAY31 RESERVOIR CONTENT, METERS	6/		742.49	738.84	737.37	738.04	738.87	
MAY31 ORC, m	7/		738.90	738.84	737.37	738.04	738.87	
BASE ECC, m	9/	738.90						
ASSUMED JUL1-JUL31 INFLOW, % OF VOL.			19.70	20.40	21.00	22.50	24.00	35.80
ASSUMED JUL1-JUL31 INFLOW, hm3	2/		1032.22	1251.19	1334.62	1296.94	1251.68	1069.16
JUL MINIMUM FLOW REQUIREMENT, m3/s	3/		311.49	311.49	311.49	311.49	28.32	311.49
MIN JUL1-JUL31 OUTFLOW, hm3	4/		834.29	834.29	834.29	834.29	834.29	834.29
VRC JUN30 RESERVOIR CONTENT, hm3	5/		5944.26	5725.29	5641.86	5679.54	5724.80	5907.32
VRC JUN30 RESERVOIR CONTENT, METERS	6/		748.44	747.25	746.79	747.00	747.25	748.22
JUN30 ORC, m	7/		748.44	747.25	746.79	747.00	747.25	748.22
BASE ECC, m	9/	749.50						
JUL 31 ORC, m			749.50	749.50	749.50	749.50	749.50	749.50
JAN1-JUL31 FORECAST,-EARLYBIRD, km3	8/		124.58	136.92	131.98	131.98	135.68	136.92

1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW) MINUS OBSERVED INFLOW.
2/ PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS. 4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
5/ FULL CONTENT (2510.5 KSFD) PLUS 4/ MINUS /2.
6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE.A143
7/ LOWER OF ELEV. FROM 6/ OR BASE VRC DETERMINED PRIOR TO YEAR (INTIAL),BUT NOT LESS THAN LOWER LIMIT
8/ MEASURED AT THE DALLES USED TO CALCULATE THE POWER DISCHARGE REQUIREMENTS FOR 3/.

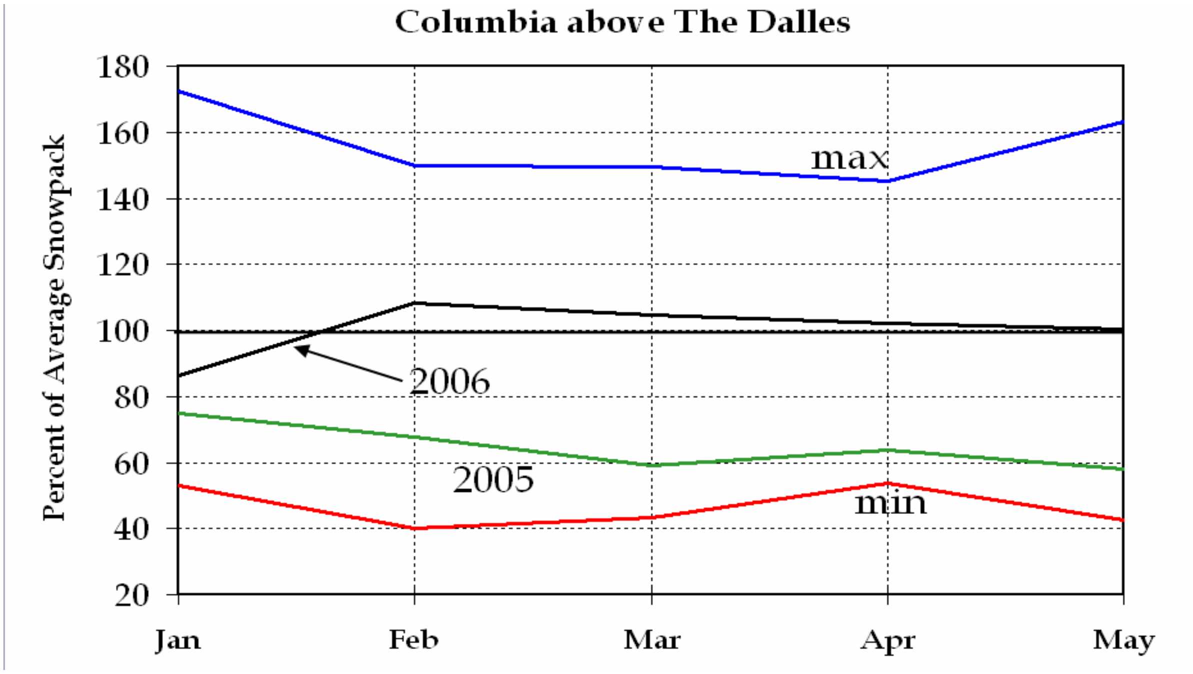
Table 6: Computation of Initial Controlled Flow, Columbia River at The Dalles, OR, For 1 May 2006

	Km^3	Maf
1-May Forecast of May – August Unregulated Runoff Volume, Maf	94.8	76.9
Less Estimated Depletions, Maf	2.1	1.671
Less Upstream Storage Corrections, Maf	24.9	20.187
Mica	6.9	5.571
Arrow	4.4	3.6
Duncan	1.7	1.353
Libby	2.3	1.898
Libby + Duncan Under Draft	0	0
Hungry Horse	1.2	0.943
Flathead Lake	0.6	0.5
Noxon Rapids	0	0
Pend Oreille Lake	0.6	0.5
Grand Coulee	4.9	3.981
Brownlee	0.7	0.582
Dworshak	1.2	1.009
John Day	0.3	0.25
Total	24.9	20.187
Forecast of Adjusted Residual Runoff Volume	67.9	55.042

	m^3/s	kcfs
Computed Initial Controlled Flow from Chart 1 of the Flood Control Operating Plan,	9911	350

VIII - CHARTS

Chart 1: Columbia Basin Snowpack



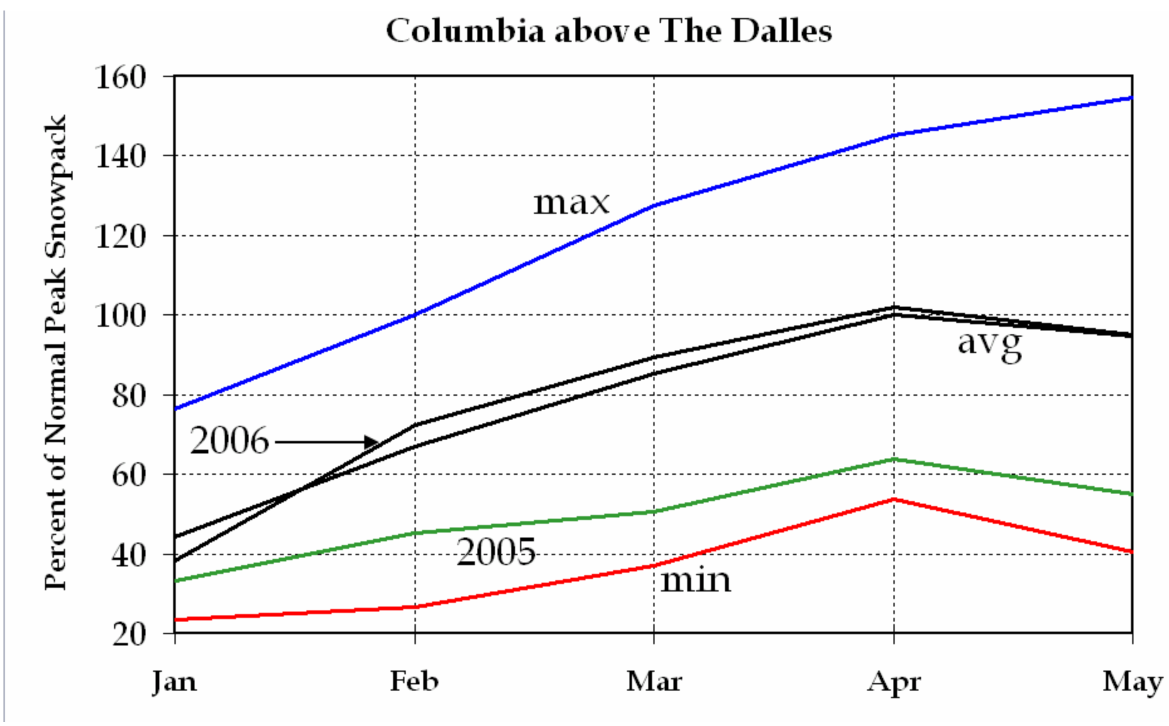


Chart 2: Seasonal Precipitation

Columbia River Basin

October 2005 – September 2006

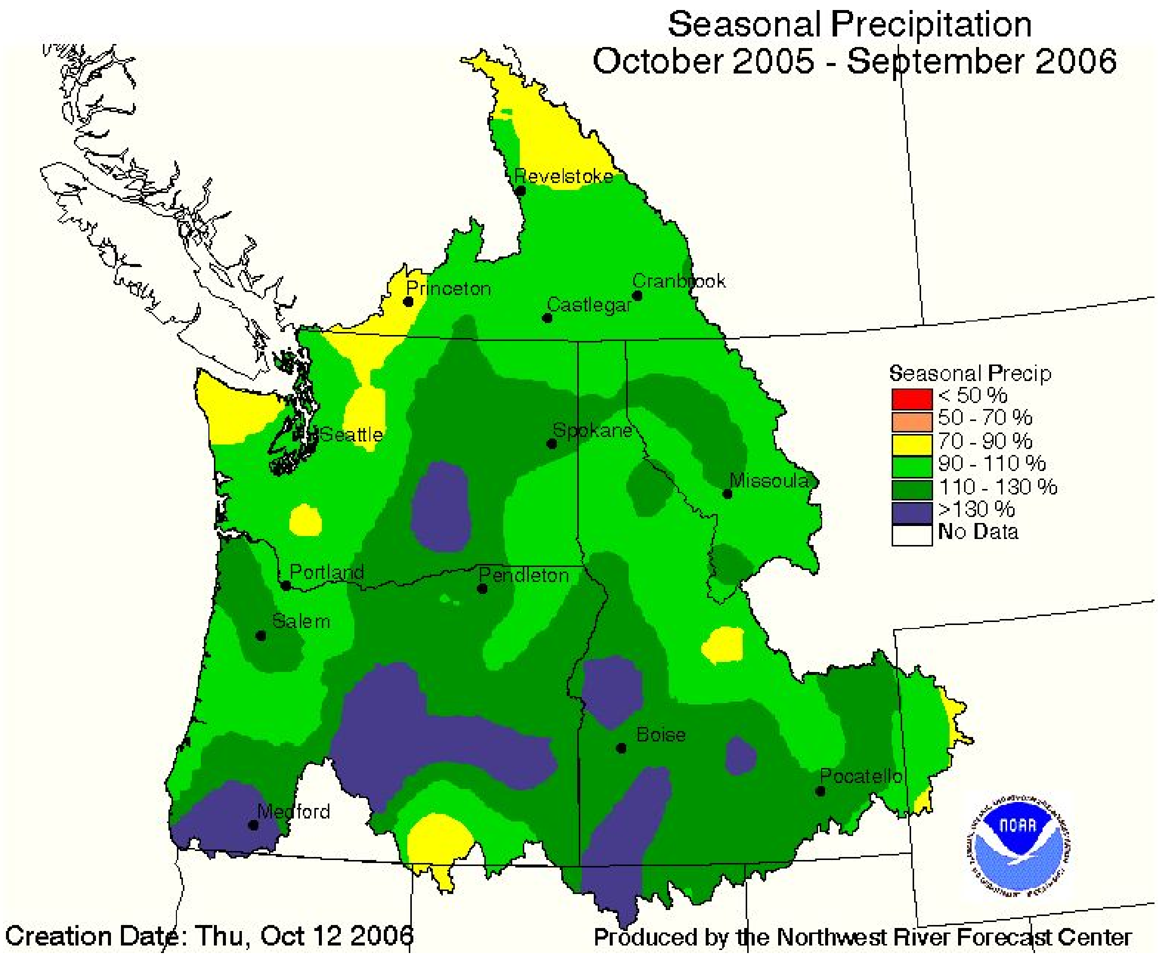


Chart 3: Accumulated Precipitation for WY 2006

At Primary Columbia River Basins

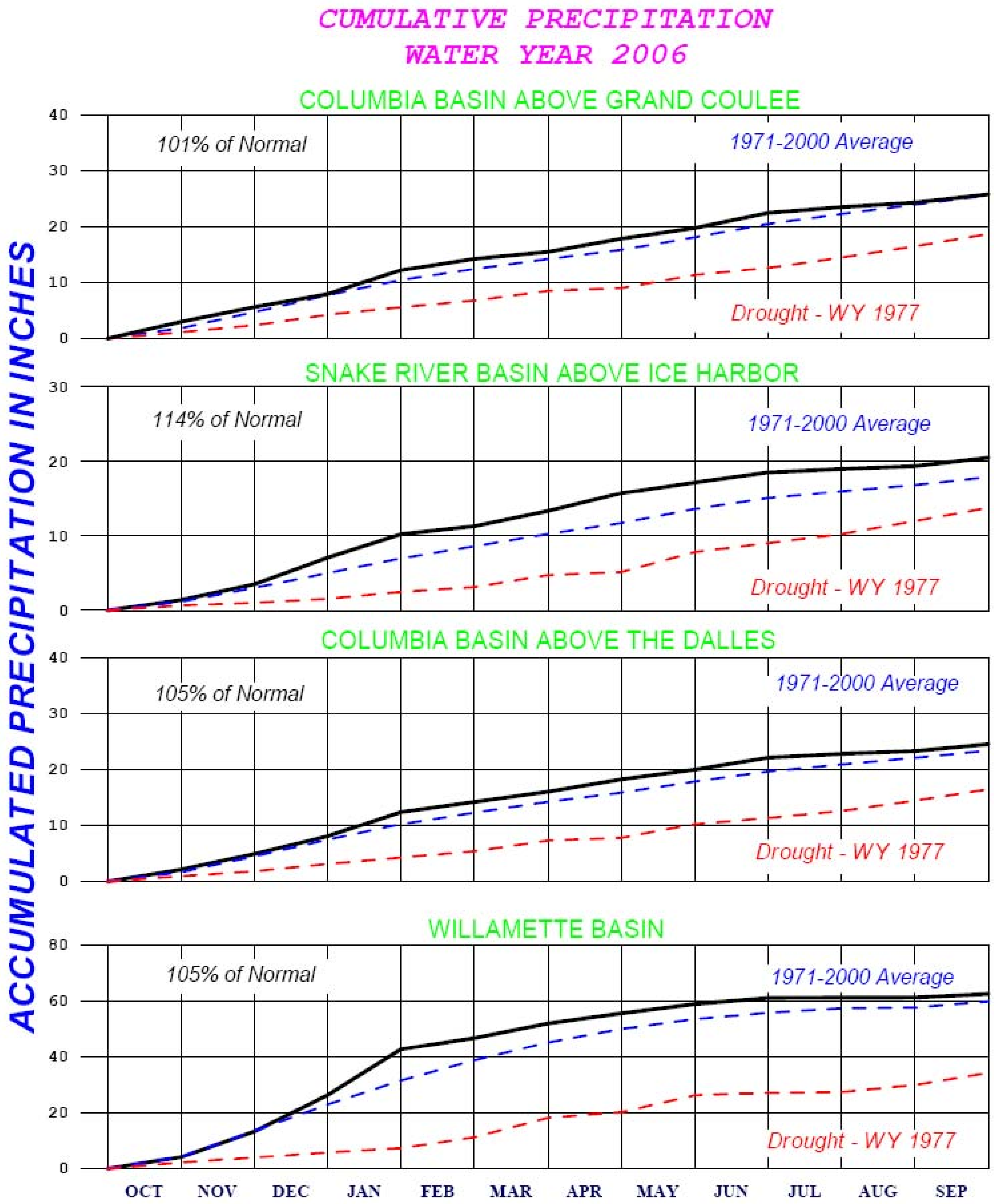


Chart 4: Pacific Northwest Monthly Temperature Departures

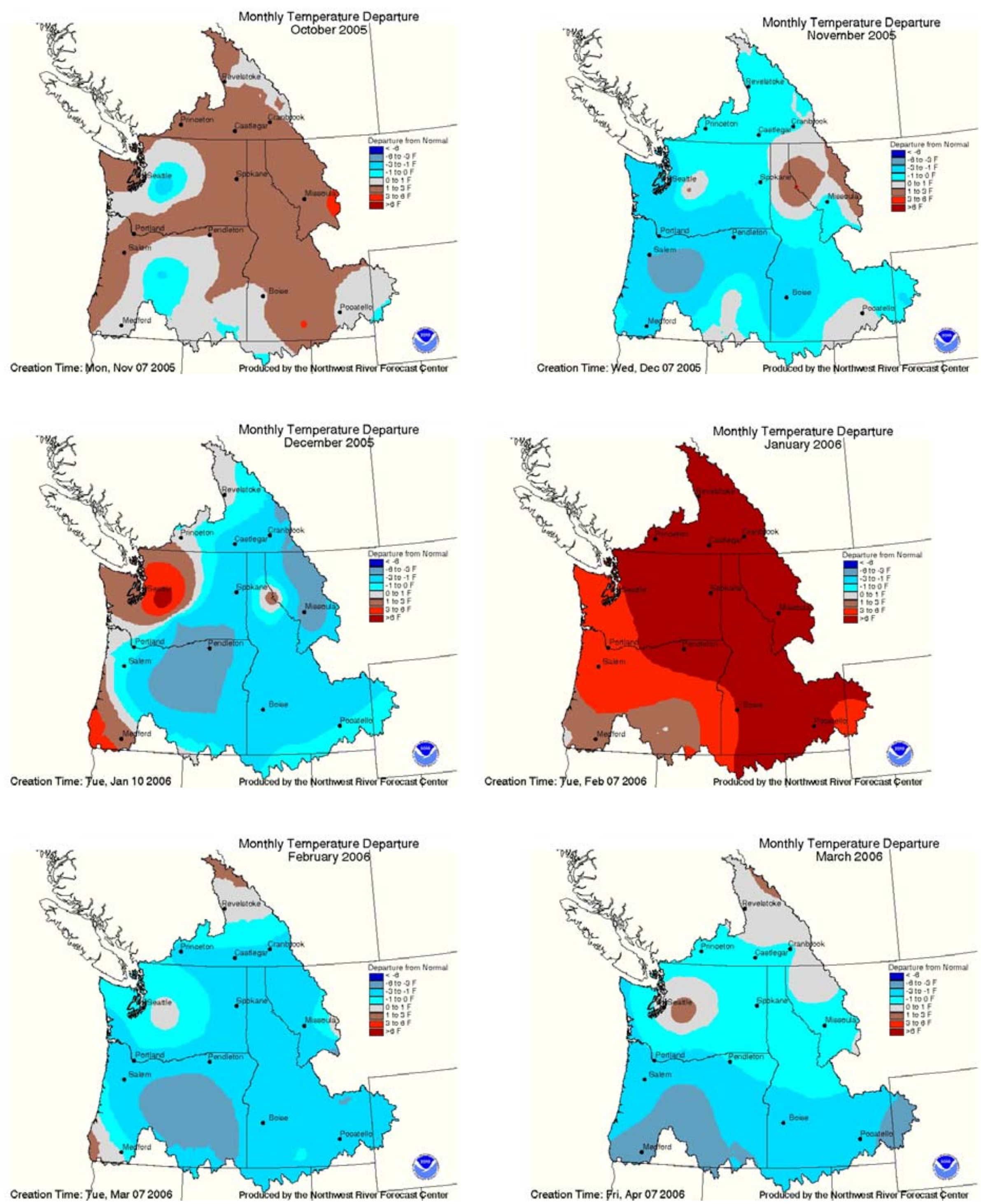


Chart 4: Pacific Northwest Monthly Temperature Departures Continued.

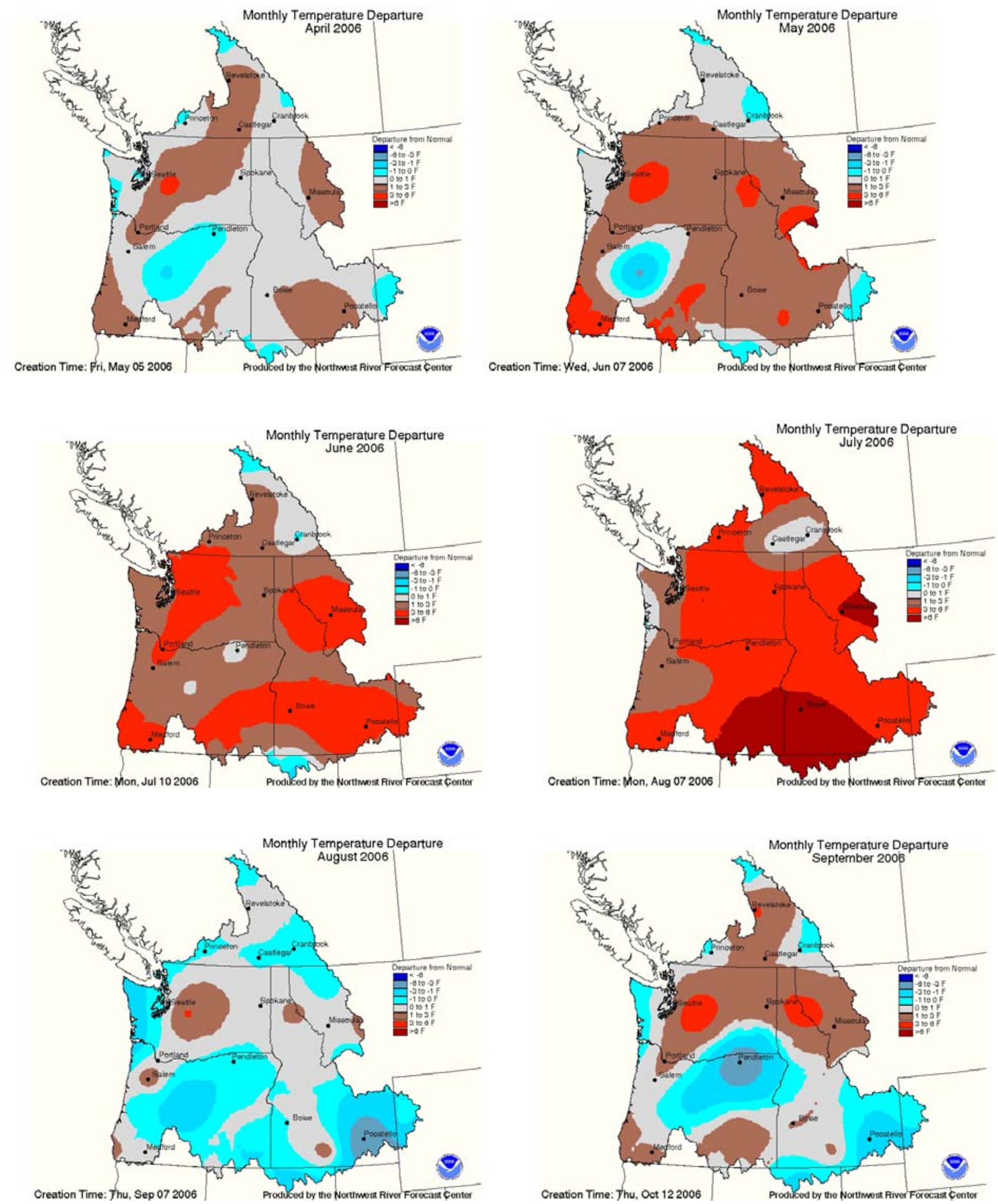
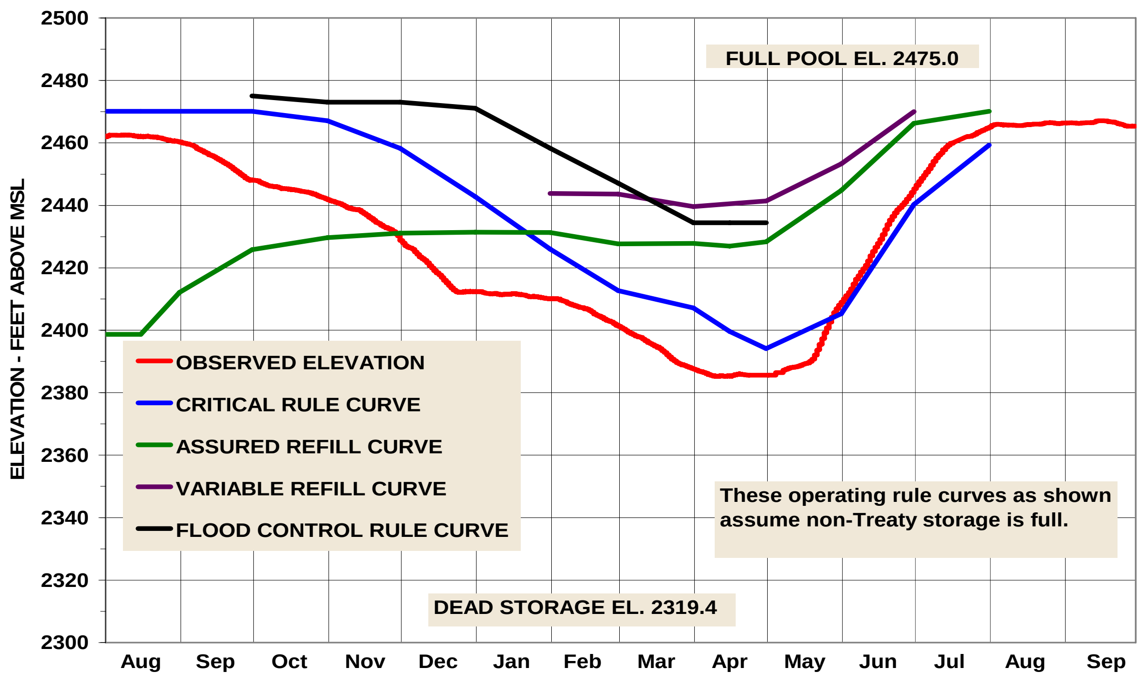


Chart 5: Regulation of Mica

1 August 2005 – September 2006



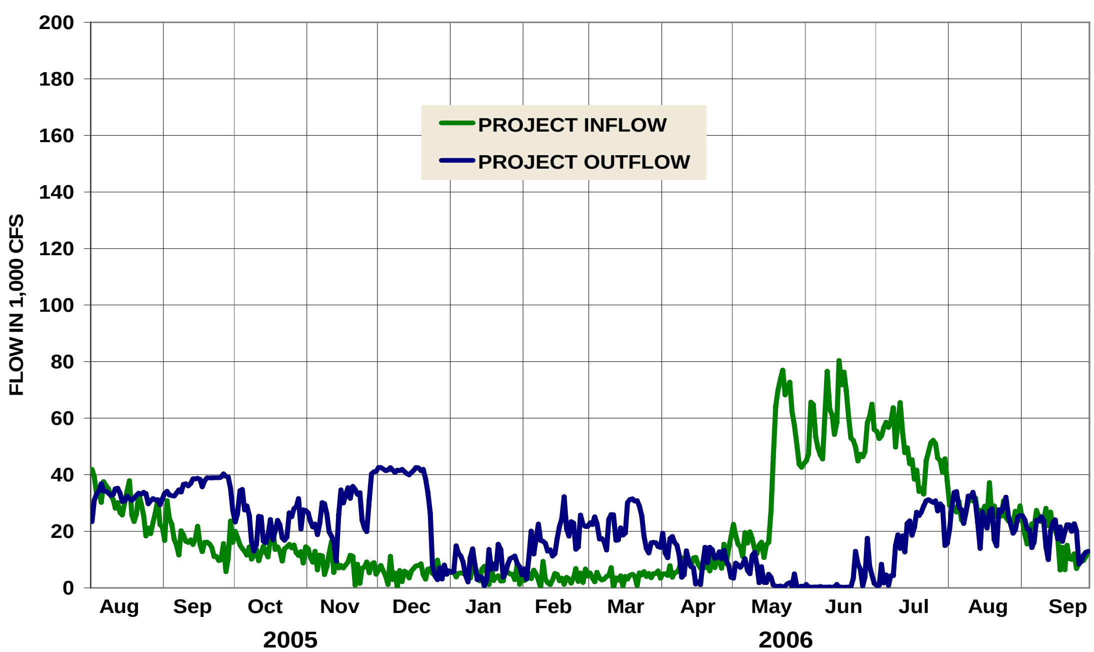
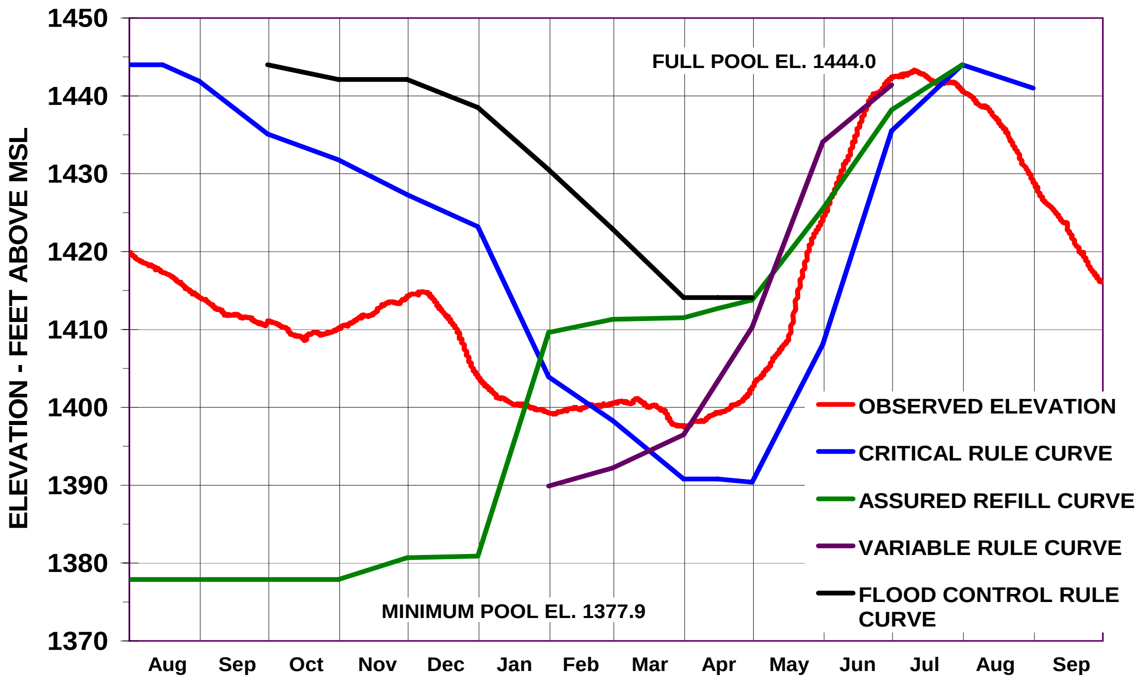


Chart 6: Regulation of Arrow

1 August 2005 – September 2006



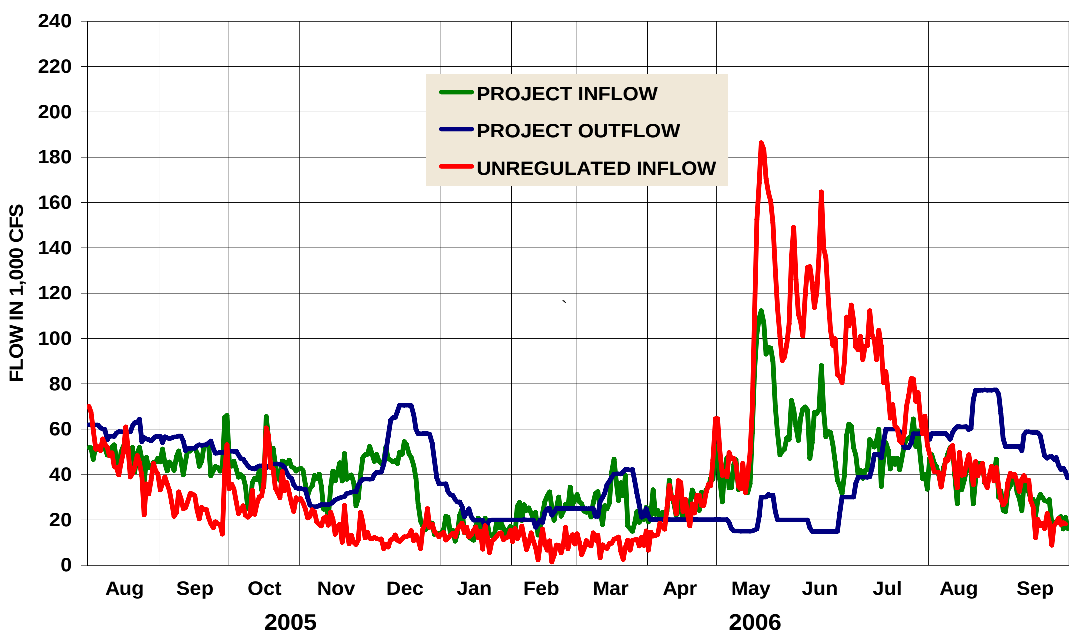
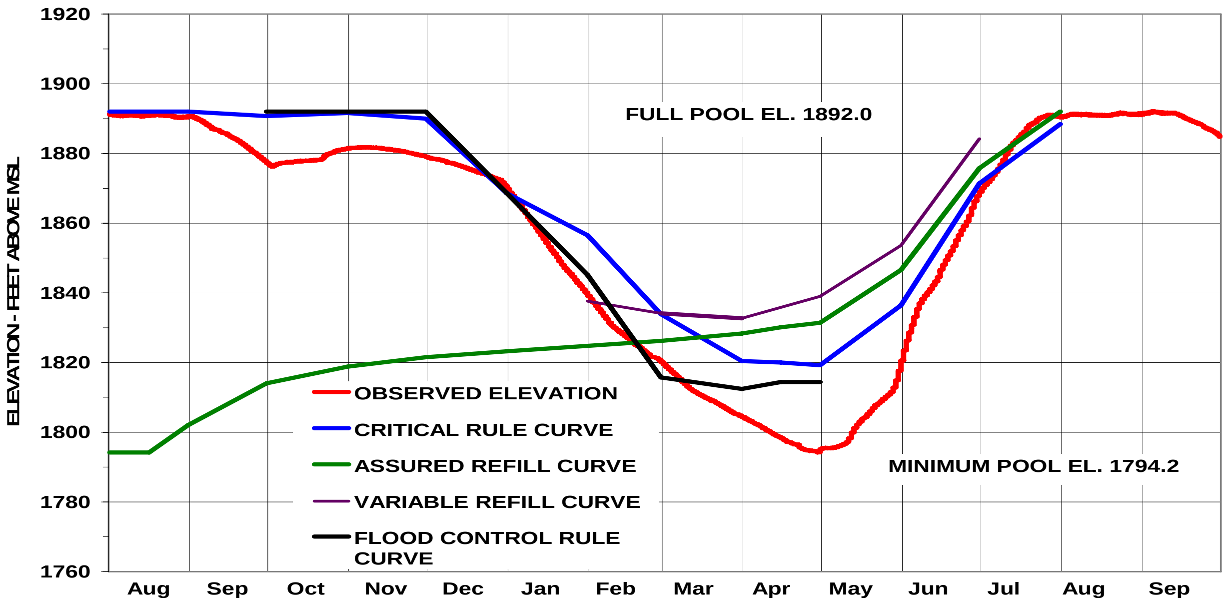


Chart 7: Regulation of Duncan

1 August 2005 – September 2006



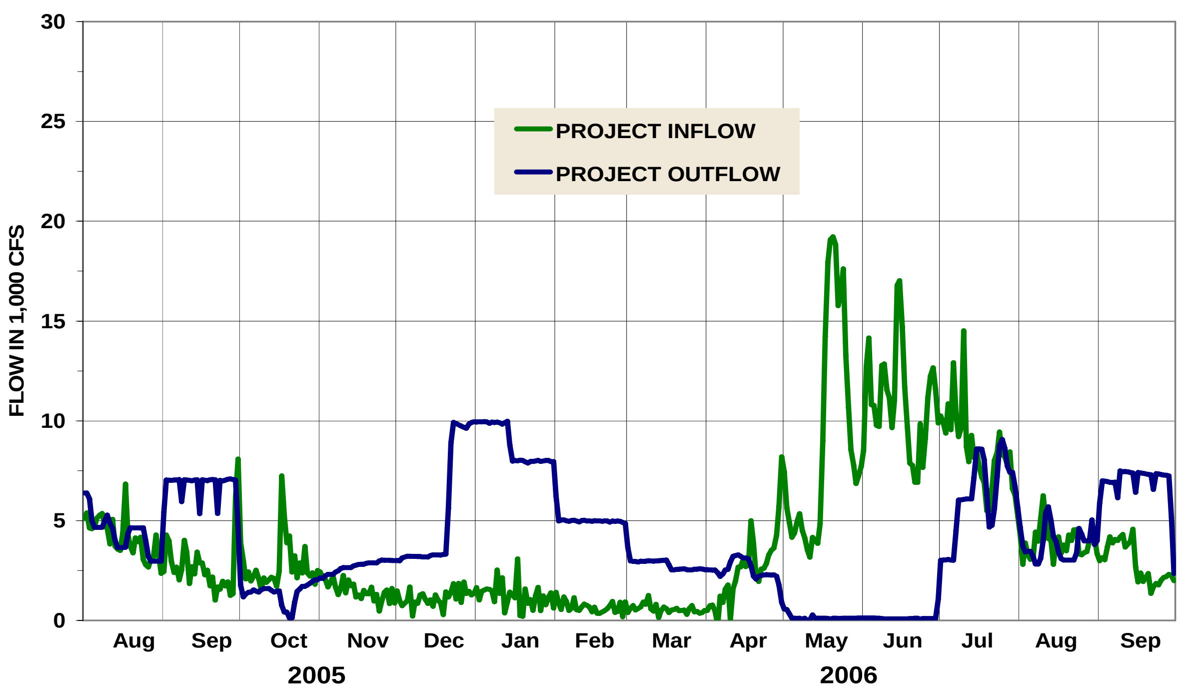
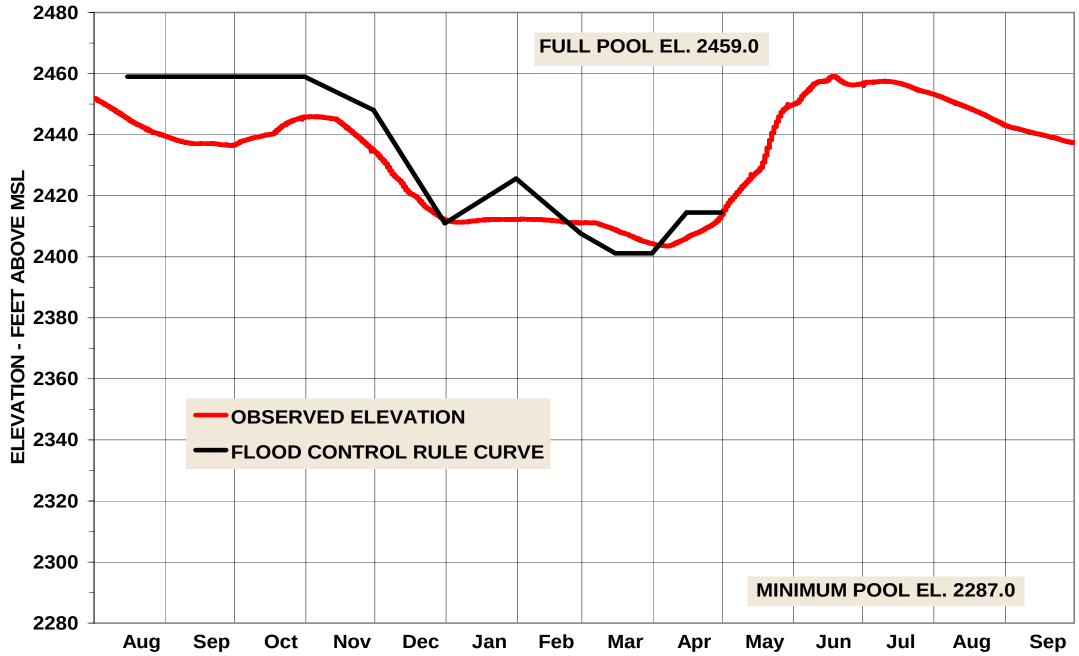


Chart 8: Regulation of Libby

1 August 2005 – September 2006



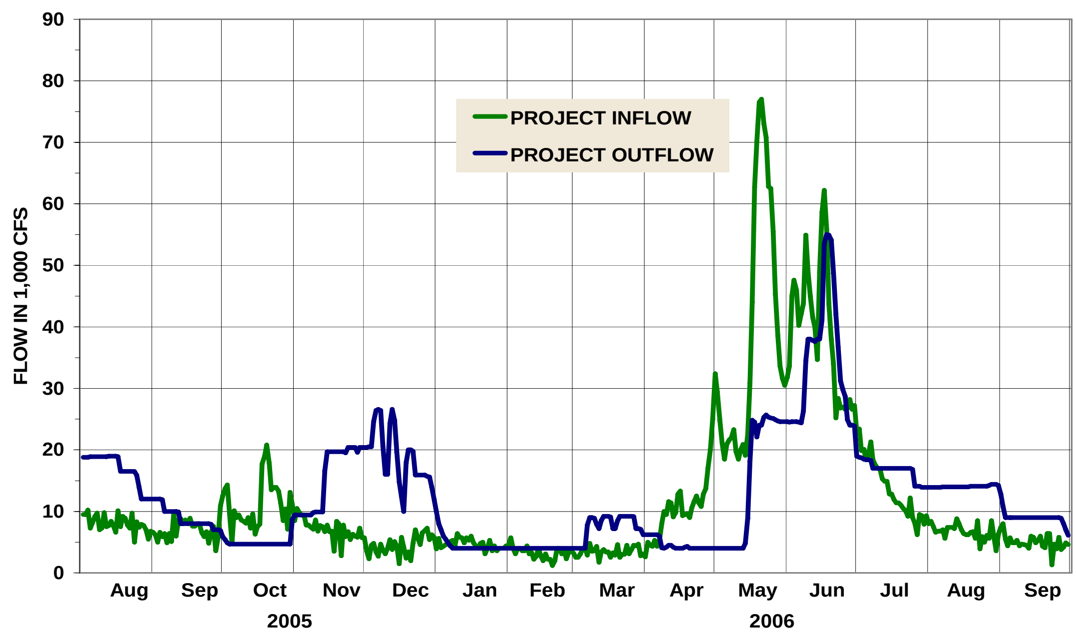
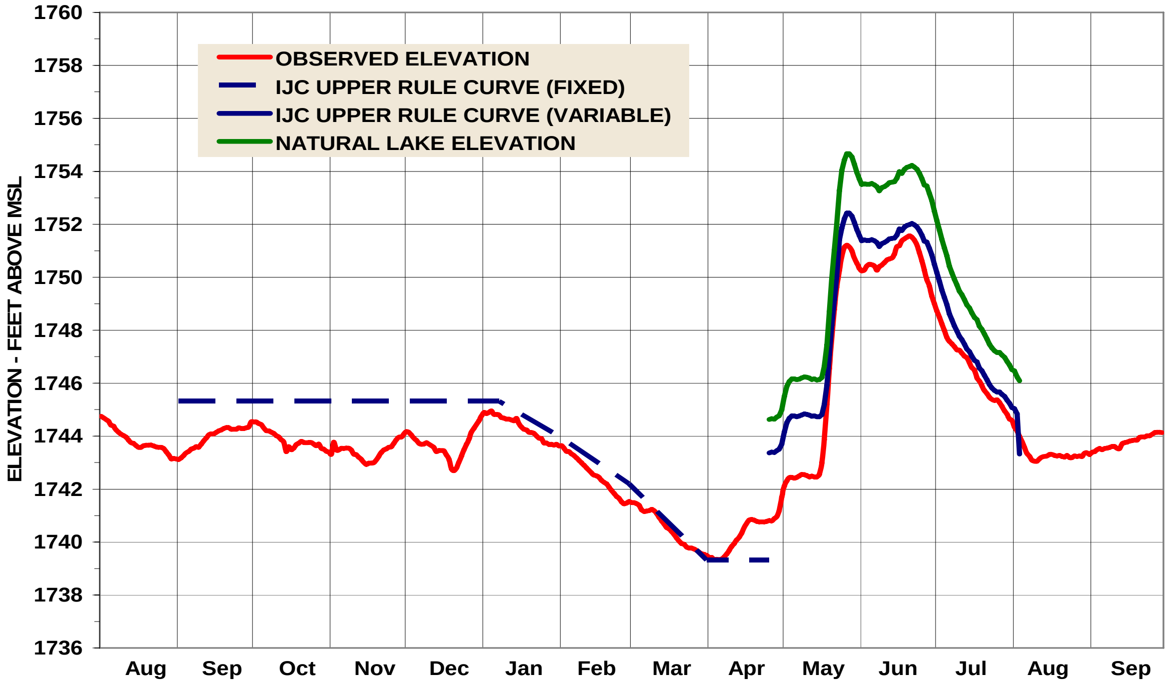


Chart 9: Regulation of Kootenay Lake

1 August 2005 – September 2006



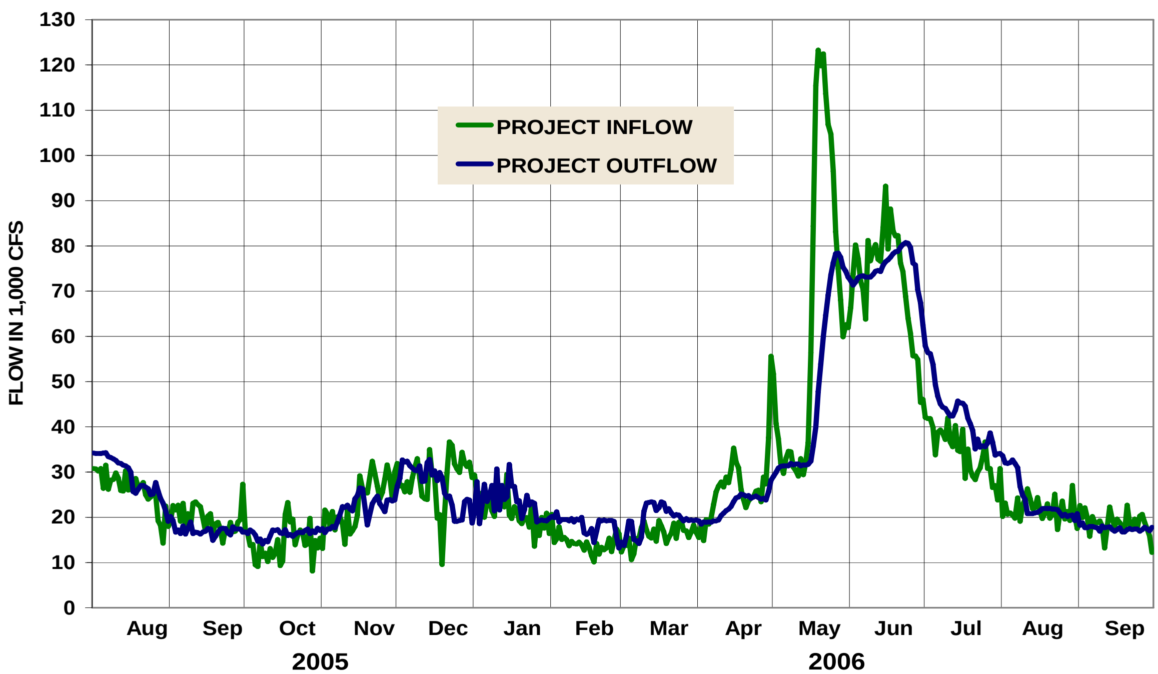


Chart 10: Columbia River At Birchbank

1 August 2005 – 31 August 2006

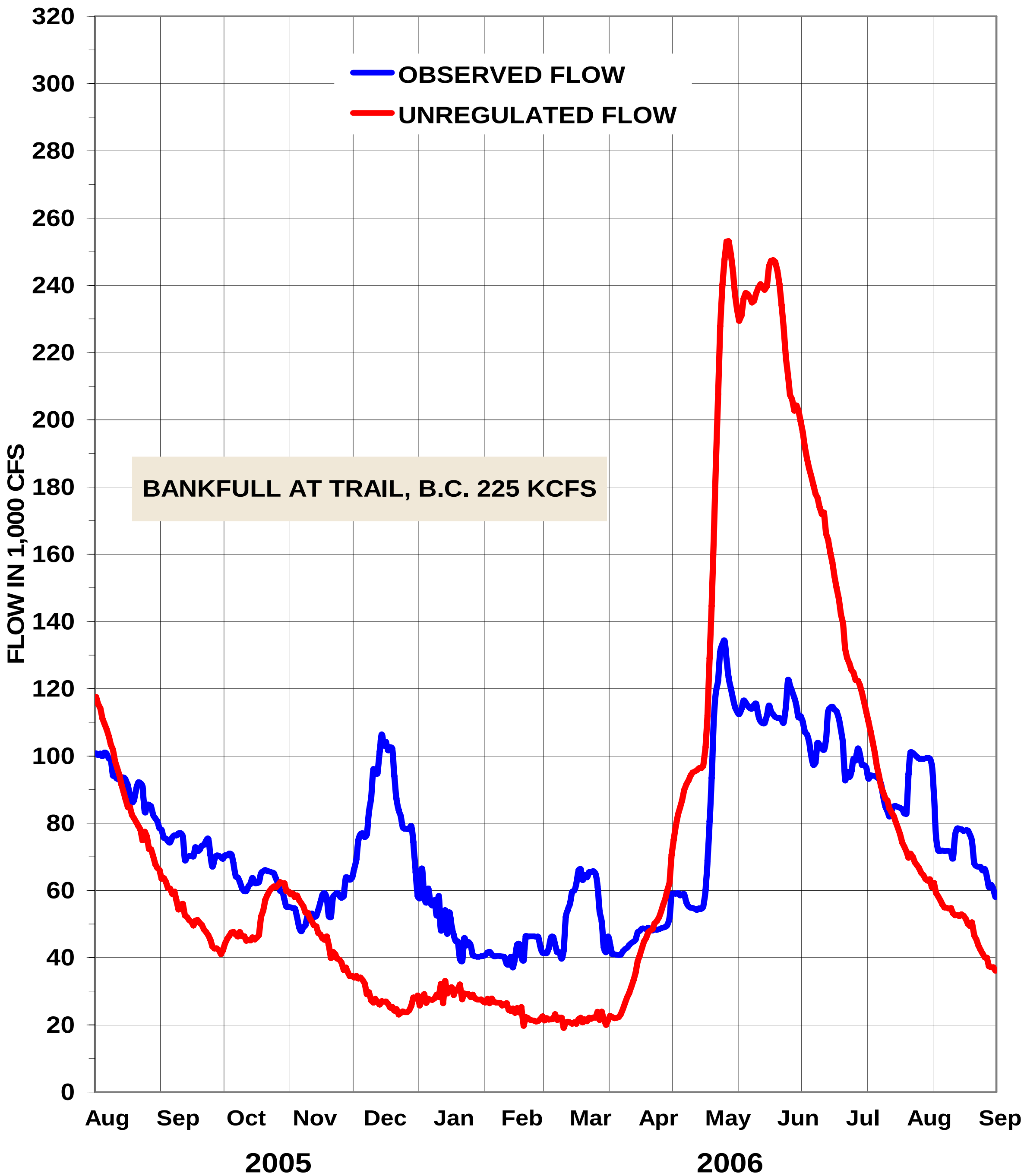
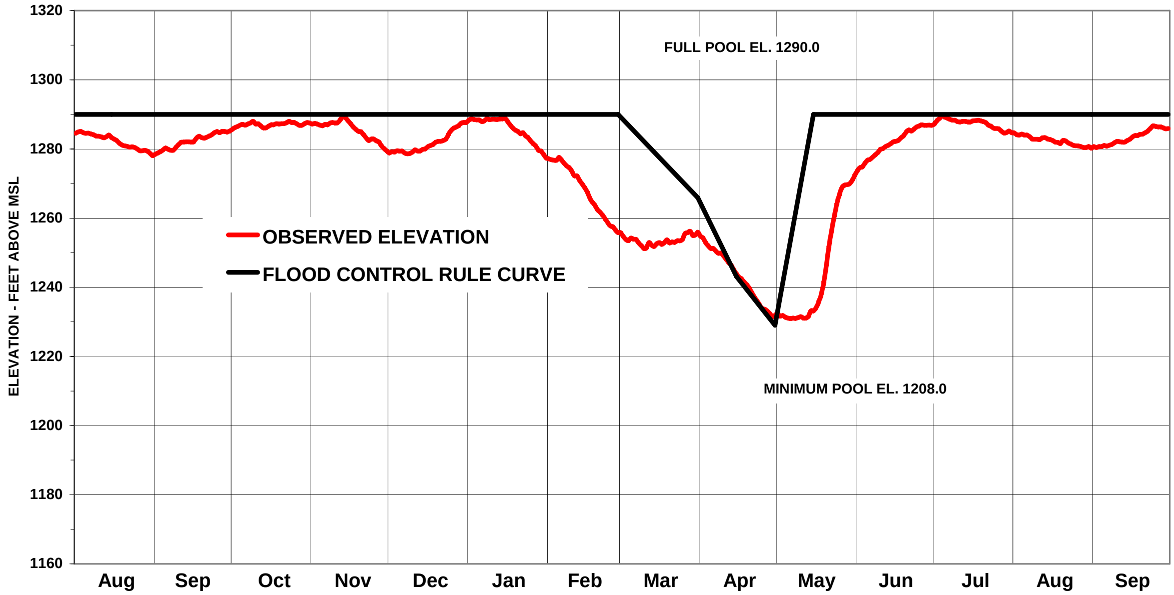


Chart 11: Regulation of Grand Coulee

1 August 2005 – 30 September 2006



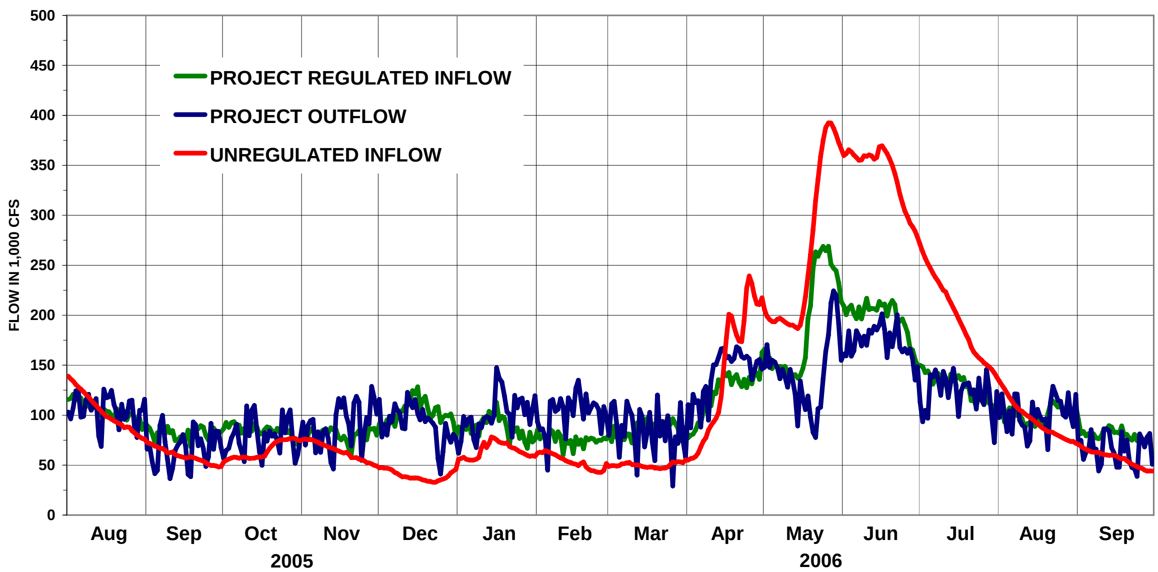


Chart 12: Columbia River At The Dalles
Summary Hydrograph
1 August 2005 – 30 September 2006

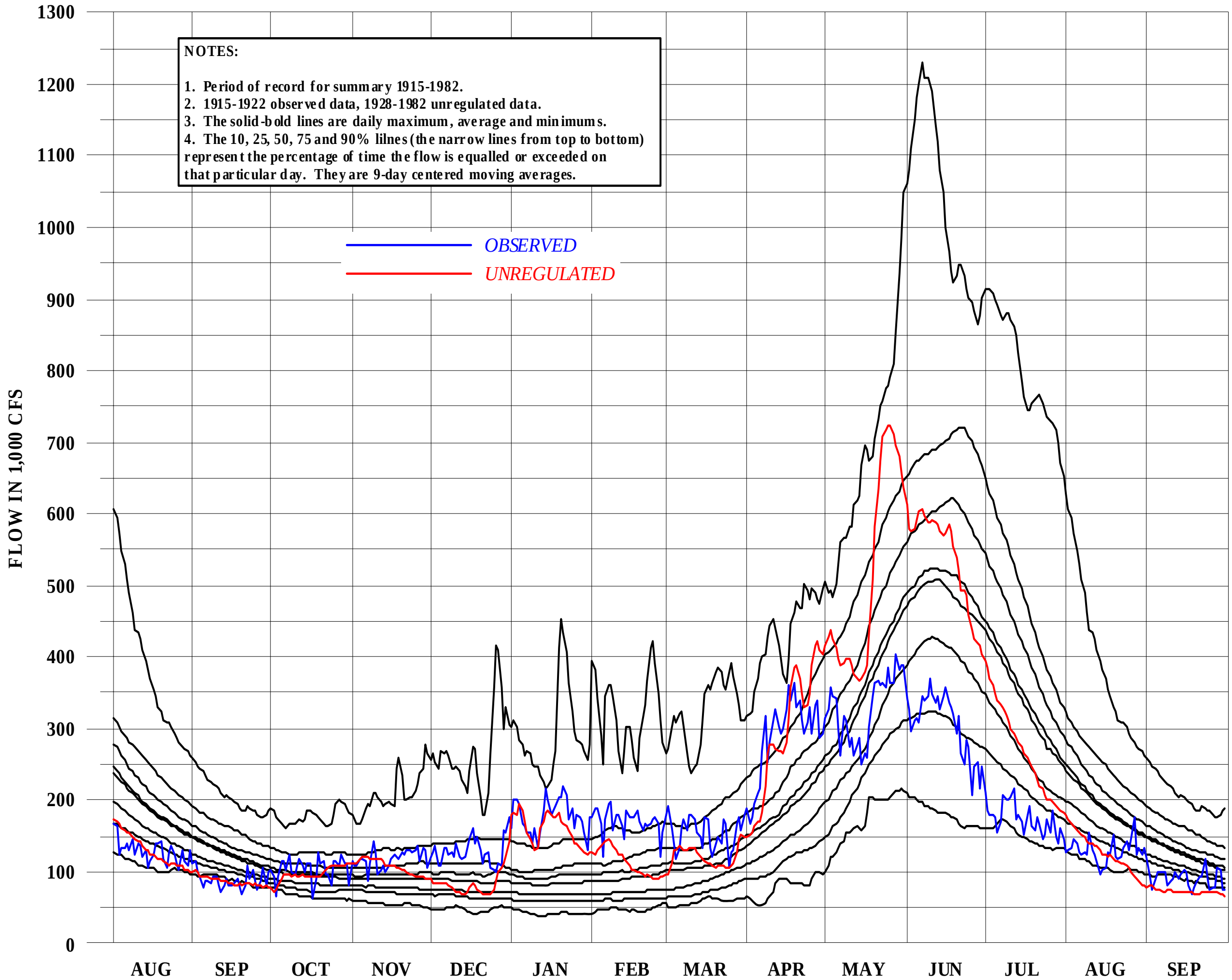


Chart 13: Columbia River at The Dalles

Re-Regulation Plot

1 April 2006 – 31 July 2006

Chart 14: 2006 Relative Filling

Arrow and Grand Coulee